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A Business Case for On-Site Generation: The BD Biosciences Pharmingen Project

Prepared for the Office of Electric Transmission and Distribution, Transmission Reliability Program

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Environmental Energy Technologies Division

September 2003

The work described in this report was coordinated by the Consortium for Electricity Reliability Technology Solutions and was funded by the Assistant Secretary of Energy for the Electric Transmission and Distribution, Transmission Reliability Program of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098.

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Preface

Distributed generation is currently moving from possibility to reality, and likewise assessing the viability of systems must move from the back of the envelope to hard financial analysis.

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Glossary

AC: alternating current
CEC: California Energy Commission
CERL: Construction Engineering Research Laboratory
CERTS: Consortium for Electric Reliability Technology Solutions
CHP: Combined Heating and Power
CPLEX: a trademark of CPLEX Optimization, Inc
CPUC: California Public Utilities Comission
DER: Distributed Energy Resources
DER-CAM: Distributed Energy Resources Customer Adoption Model
DG: Distributed Generation
DOD: Department of Defense
DOE: Department of Energy
FERC: Federal Energy Regulatory Commission
GAMS: General Algebraic Modeling System
GIS: Geographic Information Systems
HHV: Higher Heating Value
ISO: independent system operator
LHV: Lower Heating Value
PG&E: Pacific Gas and Electric
PPA: Power Purchase Agreement
PURPA: Public Utility Regulatory Policy Act
PV: Photovoltaic
QF: Qualifying Facility under PURPA
SDG&E: San Diego Gas and Electric Company
SoCalGas: Southern California Gas Company

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This work builds on prior efforts supported by prior DOE and CEC and our program managers, Gil Bindewald and Pat Hoffman of DOE and Mark Rawson and Laurie ten Hope of CEC are also hereby recognized. Finally, this work builds on the work of prior visitors to the Berkeley Lab, F. Javier Rubio and Cornelia Kawann.

Executive Summary

Deregulation is haltingly changing the United States electricity markets. The resulting uncertainty and/or rising energy costs can be hedged by generating electricity on-site and other benefits, such as use of otherwise wasted heat, can be captured. The Public Utility Regulatory Policy Act (PURPA) of 1978 first invited relatively small-scale generators (≥ 1 MW) into the electricity market. The advent of efficient and reliable small scale and renewable equipment has spurred an industry that has, in recent years, made even smaller (business scale) electricity generation an economically viable option for some consumers. On-site energy capture and/or conversion, known as distributed energy resources (DER), offers consumers many benefits, such as economic savings and price predictability, improved reliability, control over power quality, and emissions reductions. Despite these benefits, DER adoption can be a daunting move to a customer accustomed to simply paying a monthly utility bill.

San Diego is in many ways an attractive location for DER development: It has high electricity prices typical of California and a moderate climate, i.e. energy loads are consistent throughout the year. Additionally, the price shock to San Diego Gas and Electric (SDG&E) customers during the summer of 2000 has interested many in alternatives to electricity price vulnerability.

This report examines the business case for DER at the San Diego biotechnology supply company, BD Biosciences Pharmingen, which considered DER for a building with 200-300 kW base-load, much of which accommodates the refrigerators required to maintain chemicals. Because of the Mediterranean climate of the San Diego area and the high rate of air changes required due to on-site use of chemicals, modest space heating is required throughout the year. Employees work in the building during normal weekday business hours, and daily peak loads are typically about 500 kW.

Yearly energy bills prior to DER were approximately $315,000. BD Biosciences Pharmingen contracted Clarus Energy to install and maintain two 150 kW natural gas engines on-site, and agreed to purchase electricity from Clarus Energy at a constant price per kilowatt-hour (kWh). BD Biosciences Pharmingen predicts savings of $70,000 on their annual energy bill. Recovered heat from the engines is used for building heating, and Clarus Energy does not charge BD Biosciences Pharmingen for this energy.

The BD Biosciences Pharmingen site was modeled in the Distributed Energy Resources Customer Adoption Model (DER-CAM), a model developed at Berkeley Lab to determine economically optimal DER systems to install at a given site. Various cases were considered to confirm the financial estimates provided by the company and examine the economics of DER systems not chosen by Clarus Energy.

Work on customer adoption of distributed energy resources (DER) has been ongoing at Berkeley Lab for three years. This effort has focused on the adoption of small-scale (<500 kW) generators, especially where combined heat and power (CHP) and multiple

generation technologies are chosen. The most significant achievement of this effort has been the development of the DER-CAM.

DER-CAM inputs include the site's end-use energy load profiles, tariff structure under which the site buys electricity and other fuels, and a database of technology costs and performance. The output is a set of DER technologies to install (if any) and their hourly operating schedule as well as utility purchases, selected to minimize annual costs of meeting energy demand for the site.

DER-CAM is a pure optimization model and can serve as a basis for the evaluation of real world projects that have been developed subject to numerous constraints and considerations not represented in DER-CAM.

Initial DER-CAM runs calculated the total yearly energy costs at BD Biosciences Pharmingen prior to DER installation and with the chosen DER system. These runs were successful in confirming the proper representation of the site. Additional DER-CAM runs were done to examine whether yearly energy costs could be reduced even more. One case considered all DER technology types and capacities (case 2), while another considered only the type and size of equipment selected by Clarus Energy (case 4), 150 kW natural gas engines. Further runs were done to examine the sensitivity of results to variations in spark spread (the ratio of electricity costs to natural gas costs), standby charges, and flat-rate electricity pricing.

Table 1 presents the DER-CAM results from the initial runs. DER-CAM reports yearly site energy costs at $334,000 prior to DER installation (case 1) (compared to the site's $315,000 estimate), and $234,000 with the two 150 kW natural gas engines chosen (case 5) (compared to the site's $245,000 estimate). Yearly energy costs include capital costs of equipment, operation and maintenance of equipment, and the costs of purchasing electricity and natural gas from SDG&E. This is a 30% savings over the no-DER base case.

Economic optimization runs suggest the potential for even greater savings. Yearly energy costs could be reduced to $224,000 (67% of base case) by installing three 150 kW generators, and could be reduced to $220,000 (66% of base case) by installing one 500 kW generator.

The spark spread sensitivity showed that, over a large spark spread range with natural gas prices ranging from 50% to 200% of current prices, with constant electricity prices, optimal technology selection remained the same. This result emphasizes the high value to displacing utility electricity.

The standby charge sensitivity showed that optimal DER capacity decreases if standby charges are larger than $2/kW. While SDG&E currently charges a $2.73/kW standby charge, it was waived for this project in exchange for higher demand charges.

The flat rate sensitivity showed that optimal capacity decreases when electricity tariffs are a flat $/kWh charge. Current time-of-use rates with demand charges encourage at least some DER capacity to handle day-time loads above the base-load of the site, even though this additional capacity will not be used for half of the day or more.

Assignment of California Public Utility Commission (CPUC) rebates for DER was done in DER-CAM a priori for any DER system that could potentially meet the efficiency requirements of the rebate. However, the solutions provided by DER-CAM do not necessarily utilize enough recovered heat to qualify the DER systems for such rebates. The Federal Energy Regulatory Commission (FERC) defined system efficiency must be above 42.5% for systems to receive CPUC subsidies[1]. DER-CAM solutions for this study ranged from 38.7% to 40.7% in cases where subsidies were assumed. DER-CAM's suggested operating schedules selected typically do not lead to system efficiencies high enough to receive subsidies. Actual DER systems restrict their operation to match their heat load more closely, thus achieving greater overall system efficiency at a loss in energy bill savings.

The BD Biosciences Pharmingen business case study demonstrates the value of DER in the San Diego area. Even for BD Biosciences Pharmingen, a relatively small DER adopter, savings of 30% or greater over current energy costs is expected. Actual savings would be even greater if a value were placed on price stability. Finally, although not currently configured to do so, the DER system could provide power during grid failure, thereby enhancing reliability.

[1] FERC document 18 C.F.R. 292.203(a) specifies the requirements of a Qualifying Small Power Production Facility and document 18 C.F.R. 292.203(b) specifies the requirements of a Qualifying Cogeneration Facility. The formula for calculating system efficiency is

$$SystemEfficiency = \frac{Electricity\,\mathrm{Pr}\,oduced(kWh) + \tfrac{1}{2}Utilized\,\mathrm{Re}\,capturedHeat(kWh)}{FuelEnergyConsumed(kWh)} \times 100\%$$

Table 1: DER-CAM Results

CASE	Technologies Selected	Annual Energy Cost	Percentage of Case 1 Cost	Annual Savings Over Base Case	Electricity Purchases	Natural Gas Purchases (including purchase for engines)	Self Generation Costs (capital costs of equipment plus maintenance)	FERC Qualifying Cogeneration Facility Efficiency
1: No invest		$ 333,733	100%		$ 273,085	$ 60,648	$ 0	
Site's estimate of annual energy Costs without DER		$ 315,000			$ 260,000	$ 55,000	$ 0	
2: Unlimited invest	1x 500 kW nat. gas engine with CHP	$ 219,614	66%	$ 114,119	$ 522	$ 147,171	$ 71,921	40.7%
3: Unlimited invest in nat. gas engines	1x 500 kW nat. gas engine with CHP	$ 219,614	66%	$ 114,119	$ 522	$ 147,171	$ 71,921	40.7%
4: Forced minimum investment in 150 kW nat. gas engines (gen. only)	3x 150 kW nat. gas engine	$ 246,661	74%	$ 87,073	$ 5,012	$ 163,762	$ 77,886	31.8%
4: Forced minimum investment in 150 kW nat. gas engines with CHP	3x 150 kW nat gas engine with CHP	$ 223,832	67%	$ 109,901	$ 1,462	$ 151,657	$ 70,714	38.7%
4: Forced minimum investment in 150 kW nat. gas engines (gen. Only) and 150 kW nat. gas engines with CHP	1x 150 kW nat gas engine, 2x 150 nat. gas engine with CHP	$ 226,447	68%	$ 107,287	$ 1,462	$ 151,662	$ 73,323	38.7%
5: Forced duplication of site decision: 2x 150 kW nat. gas engines with CHP	2x 150 kW nat gas engines with CHP	$ 233,996	70%	$ 99,737	$ 35,234	$ 144,374	$ 54,388	39.2%
Pharmingen/Clarus Energy DER System	2x 150 kW nat gas engines with CHP	$245,000	Pharmingen estimate of annual savings: $70,000. This is 78% of their no-invest costs		$ 47,500	Estimated together by Pharmingen: $197,500		

Case 1 reflects the DER-CAM estimate of baseline costs if no investments in DER are made. The unlimited cases, 2 and 3, show the DER-CAM results when any technology can be selected or if only gas engines are available, respectively. The remaining forced cases show results when a certain investment alternative is preselected and DER-CAM merely estimates the resulting financials.

Running cases where the technology choice is constrained to a certain technology and possibly size of unit are interesting in two ways. First, they show whether DER-CAM supports the size and/or number of units installed. Second, developers often have strong preference for one technology and merely size the system to match site loads. In Table 1, it can be seen from Case 4 that DER-CAM prefers three machines over the two chosen by the site, but the extra 4% reduction in costs over Case 5, site decision, is not compelling. Case 2 shows DER-CAM prefers a single larger engine, but again given the reliability risk of reliance on a single machine and general data uncertainty the argument is not fully compelling[2].

[2] DER-CAM assumes 100% generator reliability. Neither the costs of generator outage (aside from operation and maintenance costs) nor their probability of occurrence have been quantified in this study.

This study confirms certain notions regarding DER system design that the authors have observed previously. The consistent selection of natural gas engines with CHP as the generation technology by both DER-CAM and Clarus Energy show that natural gas engines are an entrenched, economically competitive DER technology. In other words, natural gas engines with CHP are the technology to beat. The low cooling load at this site seems to eliminate thermally activated cooling as an option. Economies of scale drive the DER-CAM choice towards a single 500 kW engine, and this result is robust across a wide range of sensitivities, even a doubling of natural gas prices. The result in part derives from the balance between the benefit of CHP to displace gas purchases for heating and the fuel requirement to fire the engine. In other words, while high natural gas prices lower the competitiveness of on-site power with grid power, the value of the waste heat goes up, redressing the balance. The robustness of this result to a standby change sensitivity also shows that, in general, capital costs are not a big factor in savings estimates.

Overall, DER-CAM results are very close to the chosen site system. DER-CAM suggests that either a single larger engine or a three small engine system might be preferable to the Clarus Energy two engine arrangement. However, given data uncertainty and the potential importance of issues DER-CAM does not consider, e.g. reliability, footprint, etc., results are reasonably consistent.

1. Introduction

1.1 Background

The halting national trend towards electricity market deregulation has encouraged consumers to search for alternatives to traditional tariffed utility power. Key considerations include price, price stability, reliability, power quality, and emissions. Recent improvements in small-scale on-site electricity generation technologies mean that many of these considerations are favorably addressed by the use of distributed energy resources (DER). However, the dramatic shift in paradigm from monopolistic supplier to decision enabled consumer will require considerable research and confirmation before widespread customer adoption.

San Diego appears to be an attractive region of the U.S for DER development. Not only does San Diego have the high electricity prices typical of California, but large commercial and industrial customers suffered a particularly nasty price shock during the summer of 2000. San Diego Gas and Electric (SDG&E) was the first of California's three large utility distribution companies (UDSs) to recover its historic costs and move to the age of competitively determined electricity tariffs, which the restructuring law had mandated. The extreme wholesale prices of 2000 were for a short period, therefore, actually seen and felt by SDG&E customers. This experience was short-lived but traumatic nonetheless, and interest in DER in this region quickly escalated. San Diego is also an area that relies heavily on imported electricity and the transmission that delivers it. This together with a combined gas and electric utility creates an environment favorable to distributed generation. On the other hand, the mild climate reduces the size of available heat sinks.

This report is a business case study of the San Diego based biotechnology company, BD Biosciences Pharmingen. After experiencing these price spikes and general market uncertainty, the company decided to consider on-site generation to reduce and stabilize costs. Furthermore, their Facility Operations Director, who championed the adoption of on-site generation, saw the additional benefits of accepting corporate responsibility for environmental stewardship. In 2002 the company contracted with Clarus Energy to purchase, install, and operate a DER system on site.

Berkeley Lab has been researching the market potential of small-scale on-site generation, especially those involving combined heat and power (CHP) applications. A software program, Distributed Energy Resources Customer Adoption Model (DER-CAM), has been developed to analyze the economics of DER adoption at specific sites and to determine an economically optimal DER system.

The most recent step in two years of work on DER-CAM has been a case study and model validation project. Five DER adoption sites were studied in detail, including the BD Biosciences Pharmingen site. The results of this study are reported in Bailey *et al* (2003). The report herein considers this site in more detail, examining the business decisions made by the company regarding distributed energy resources (DER) installation, and serves as a detailed business case for DER adoption.

1.2 Purpose of Research

The purpose of this work is to support the wider CERTS research agenda in DER, which is the development and commercialization of the CERTS Microgrid (Lasseter 2002). The CERTS Microgrid is a cluster of electrical and heat loads that functions semi-autonomously from the grid by controlling itself using power electronics associated with many emerging small scale generators. This work is intended to review in detail the adoption decision of one site and explore the business case for the project. This analysis will hopefully help guide wider CERTS research in a direction that will make it the most beneficial possible to its ultimate users.

1.3 Method & Application Summary

After identifying BD Biosciences Pharmingen as a DER adopter, its participation in the case study project was requested. The company agreed and a questionnaire was sent, asking for thorough information about their decision process, the DER technologies installed, how the technologies were integrated with site energy systems, and the information used to support the decision.

A visit to the site in August 2002 by the DER-CAM team established a good rapport with company staff and the project developer, Clarus Energy. The site's energy situation and interest in DER was discussed, as well as its business arrangement with Clarus Energy and their approach to DER system design and deployment. The site was able to provide the Berkeley Lab team with pertinent time-of-day electricity load information, utility bills, and DER savings estimates.

Information obtained from the questionnaire and site visit was then manipulated into the needed inputs to DER-CAM. Model results were obtained, runs were refined to reflect site data more accurately, and several cases and sensitivity analyses were conducted. Three model validation cases were then examined to compare DER-CAM and site estimates of costs (before and after DER adoption) as well as to compare DER-CAM and company choices of optimal DER systems. Additionally, sensitivity analyses were done regarding the spark spread (ratio of electricity cost to natural gas cost), standby charges, and flat rate electricity prices (instead of the current scheme of time-of-use pricing and demand charges). These sensitivities were done to examine how these variables would affect DER adoption.

A second visit was made in February 2003 to view the DER system in operation and further discuss the project, and its early performance.

2. BD Biosciences Pharmingen Background

BD Biosciences Pharmingen, a business unit of BD Biosciences (a Fortune 500 company), is a biotechnology company producing products for immunology, cell biology, neurosciences, molecular biology, and protein expression systems. Primarily, the company manufactures protein-based re-agents for the life sciences research industry, and is the fourth largest biotechnology employer in San Diego.

Figure 1: BD Biosciences Pharmingen, San Diego, California

The company operates multiple sites in the US, with buildings ranging from administrative offices to manufacturing sites to warehouses. This San Diego site consists of two adjacent buildings: one is dedicated to administrative office space and R&D, and the other, 10995 Torreyana Road, is a manufacturing facility. It is at the latter site, a 3700 m^2 (40,000 ft^2) building that Clarus Energy has installed two 150 kW natural gas fired reciprocating engines with CHP to cover the building's base electrical load and thermal space heating requirements. All data and analysis herein refers to the manufacturing facility only, not the entire San Diego site.

Although utility blackouts were one of the motivations for DER adoption, the natural gas engines are not currently configured to run in a stand-alone manner in the event of a utility blackout. Thus, this system does not improve the site's electricity reliability. It would be possible to configure the engines with the site's existing diesel backup generator, or with power electronics, to allow for natural gas engine operation during utility blackouts.

The climate at the site is very moderate (average yearly high and low temperature are 20°C (70°F) and 14°C (57°F) respectively), but due to its close proximity to the Pacific Ocean, this location typically experiences fog for at least a few hours on most days. Consequently, the outside temperature is often below desired indoor temperature. In addition, building air must be constantly flushed out and replaced by fresh air from outside due to the use of chemicals. For health and safety reasons, this procedure continues 24 hours a day, even though most manufacturing occurs from 9 am to 5 pm[3]. As a result, heating is required almost all year round and around the clock: further, the facility must strictly remain within the temperature range necessary to preserve its chemical supplies and products[4].

Figure 2: Laboratory at the Site

[3] The building continuously executes about 7 air changes/ hour (100% fresh air with no recirculation)
[4] 21-22°C (70 –71°F) during business hours, 16- 26°C (60 –78°F) during all other hours.

3. Clarus Energy Background

Clarus Energy Partners, L.P. is a young partnership between Hunt Power of Dallas, TX and the San Diego, CA based Clarus Energy management team. To energy-intensive customers, they offer to install, operate, and maintain on-site DER systems that provide energy at a flat rate. Clarus Energy can offer stable prices by negotiating long-term (five year) natural gas contracts. They accept considerable risk in comparison to many DER providers who offer customers profit-sharing contracts in which the cost of energy to the customer is tied to fuel. For businesses that do not care to invest in DER equipment or be responsible for its operation, Clarus Energy offers certain, stable prices in an uncertain energy market.

4. DER Motivations, Barriers, and Solutions

Implementing a DER system at BD Biosciences Pharmingen was not an obvious or initially popular choice to most of the personnel involved, nor was it common enough in the industry to be casually implemented. As such, the interplay of motivations, barriers, and an eventual solution is central to the DER adoption decision.

4.1 Motivations

The company decided to consider distributed generation to reduce costs and increase availability. At the time, it believed that it was facing rising energy costs and sought options to lower costs and mitigate price risk. On the other hand, it did not want to increase its exposure to operation, maintenance, or capital expenditure risks that would accompany ownership of generation facilities. In fact, the company wanted to continue only to buy electricity, as if from a utility.

The site had been experiencing an average of ten electrical outages a year, lasting from one minute to 14 hours each. Rolling blackouts were a frequent cause of outages during the California crisis of 2000 and 2001[5]. While the site has backup diesel generation for critical loads such as refrigeration, this generator is not large enough to maintain manufacturing schedules and can generate at full power for only twelve hours on the fuel stored in the on-site tank. In the event of an earthquake or fire, there was a concern that their contracted diesel fuel provider may not be able to reach the facility to re-fill the tank, creating a possible 12-hour fixed barrier on outage survival. Air quality restrictions also strictly limit use of diesel generators to emergencies and testing/maintenance.

As is common with early technology adoption, the initial interest in DER came from a single DER champion within the company, Facility Operations Director, Robert Schultze. Schultze championed DER on multiple fronts: energy savings, increased electric reliability, corporate responsibility, and environmental stewardship. He campaigned actively to secure approval for the project.

4.2 Barriers

Schultze faced three significant barriers to getting DER technologies installed: the desired contract structure, the low load factor, and the relatively small potential size of DER project.

The company wanted to decrease energy bills without increasing their exposure to risk, and so looked to a third party to provide on-site energy services. The challenge came when they discovered that the typical contract contains minimum base-load usage and increasing consumption. For example, an energy contract may stipulate that the customer must have a base-load of at least 500 kW, and often this base must increase by a certain

[5] A rolling blackout is a deliberate cut in service instigated by the system operator because supply capacity cannot meet load.

percentage each year. This type of agreement was unacceptable to the company, which is actively working to decrease its energy use and product energy intensity.

Also, most developers seek customers who run their operations 24/7 and that have constant energy loads in order to minimize the levelized energy cost of DER output by spreading the capital cost over many kWh. The company's manufacturing operation at the site only runs one shift and has a base demand of about one half of its peak.

The base electricity load is approximately 200-300 kW, which is mostly consumed for refrigeration. However, most developers seek larger projects (at least 500 kW), where margins and profits can be larger.

4.3 Solutions

After rejections from some developers, Schultze finally received interest in a DER project that met the company's needs from Clarus Energy, who agreed to act as an "alternate utility" to the company by providing them with electricity and heat for a flat $/kWh price from a generation facility on site.

Clarus Energy's DER proposal was attractive. According to Schultze, the minimum-use guarantees in the contract are low enough to ignore, regardless of future energy efficiency improvements. As part of the contract agreement, the fixed $/kWh price can rise with natural gas prices. However natural gas price volatility is mitigated by Clarus Energy' long-term purchase contracts.

By downsizing the onsite generation capacity, Clarus Energy was able to work around the sites low load factor demand profile, proposing a 300 kW natural gas engine system (two 150 kW engines) along with heat recovery to support heating loads within the building. Clarus Energy was willing to work with the company despite small profit margins, in order to gain experience and acclaim in DER system development. Also, a successful project would open the realistic possibility of follow-on projects at other sites.

As discussed in Chapter 1, the current DER system is not capable of running during a utility blackout. Further research would be required to assess the cost of making the natural gas engines available during grid outages.

Schultze discussed the tendency in a competitive industry to maintain the status quo (in this case buying energy from the utility) because a risk experienced equally by all does not affect competitiveness. However, Schultze argued for the project on a strictly economic basis, demonstrating the financial incentives of the project, based only on the electricity generation alone and using the additional savings from recovered heat usage as an added benefit. He staked his reputation on the validity and accuracy of the cost analysis. Ultimately, the decision to install onsite generation with CHP was approved.

5. Data Gathering

This project was appealing to the DER-CAM team as an example business case for several reasons:

1. Generating capacity (300 kW) was within the range (up to 1 MW) DER-CAM was intended to study.
2. CHP technology, namely recovered heat from engines, is used for building heating.
3. DER adoption was motivated by financial considerations and not as a demonstration project.
4. Financial analysis was performed during the decision-making process.
5. On-site generation was to be a source of primary power, not only back-up power.
6. The involved parties were willing to discuss their project with the DER-CAM team.

During the site visits, DER-CAM team members met with Bob Schultze, Facility Operations Director for the site, and Ray Miller, Clarus Energy's Vice President of System Design. Schultze provided detailed graphs on historic electricity use, electricity peak demand, average monthly electric rates, natural gas use, and natural gas rates, including data from the first three months of DER system operation. He also provided cost projections generated for internal presentation to the board. This information is provided in *Appendix C: Data Provided by BD Biosciences Pharmingen*.

5.1 Economic Analysis

The economic incentive for this project was to stem the increasing costs of energy and to reap the benefits of a more reliable energy supply. 2001 energy bills (electricity and natural gas) were approximately $330,000 annually (see, Current Utility Rates line). The company's own estimate based on stable energy prices, shows savings to the company of $62,000/year ($434,000 over the course of their seven year contract). Based on experiences with the San Diego rate shocks in 2000-1, the possibility of further utility rate increases were considered in which case their yearly savings could be $115,000 or more. The current DER system does not, however, improve energy reliability. This is discussed in Section 5.2.4.

Figure 3, provided by the site, shows projected cumulative undiscounted natural gas and electricity costs over the seven-year contract period for several scenarios. The company determined that, at the then-current rates, it would cumulatively save at least $434,000, undiscounted, on total utility expenses (electricity and gas). Figure 3 also shows that the site's savings increase to $813,000 if rates increase by $0.02/kWh as the California Public Utility Commission has proposed[6]. Even if rates went down to pre-deregulation levels, the $0.08/kWh used by the company in its analysis, it would break even as long as

[6] SDG&E originally submitted filing 02-05-031 to the CPUC in July 2002 to request rate increases effective January 1, 2003. It was later merged with other filings and submitted on Dec 27, 2002 (Filing AL 1463-E). The consolidated filing went into effect on Jan 1, 2003.

rates do not drop earlier than 32 months after equipment installation. Thus, their rate exposure was limited to just fewer than three of the seven years. If the site were to enable their natural gas engines for use during grid outages and assigned value to the improved reliability, then the potential payback for this project might be even larger.

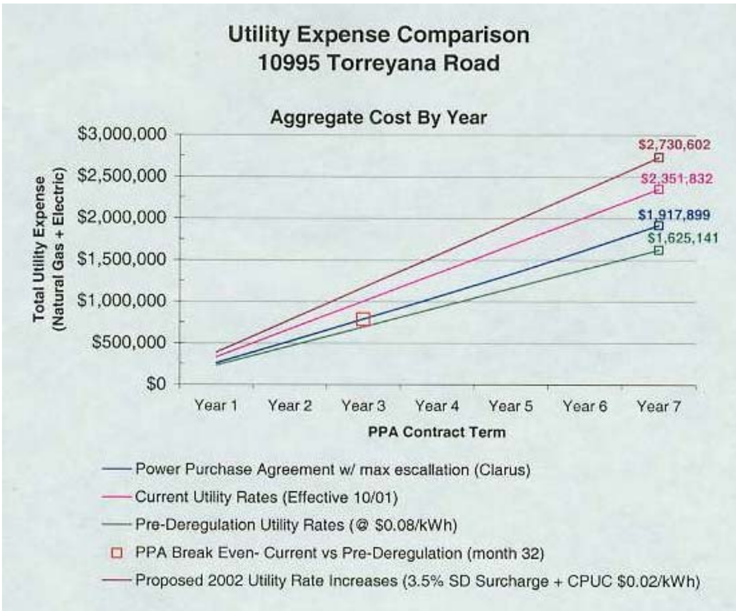

Figure 3: Cumulative Energy Expense Projections Provided by BD Biosciences Pharmingen

In order to keep his argument simple, Schultze presented the straightforward argument to the board that onsite generation of electricity is cheaper to the company than purchasing grid electricity. Without considering potential reliability increases and reduced energy consumption due to CHP, he was able to present a winning economic argument.

The company also provided Figure 4, which presents disaggregated annual cost estimates. This figure accounts for the lower natural gas purchases required because of CHP. In the figure, PPA stands for power purchase agreement and refers to the company's agreement with Clarus Energy. E-depart charges are fees still owed to the utility for an energy load after that load has been supplied by another utility or by self-generation[7]. The left column shows the company's total energy cost with DER, the sum of e-depart charges from SDG&E, electricity purchased from Clarus Energy, electricity purchased from SDG&E, and natural gas purchased from SDG&E. The right column shows the total energy cost without DER, the sum of electricity and natural gas purchases from SDG&E.

[7] As stated in SDG&E's Schedule E-Depart, "Each billing period the Departing Load of the customer shall be billed the Nuclear Decommissioning (ND) charge, Public Purpose Programs (PPP) Charge, and the Departing Load Cost Responsibility Surcharge (DL-CRS) as set forth on the customer's otherwise applicable tariff and Schedule DL-CRS."
http://www.sdge.com/tm2/pdf/E-DEPART.pdf

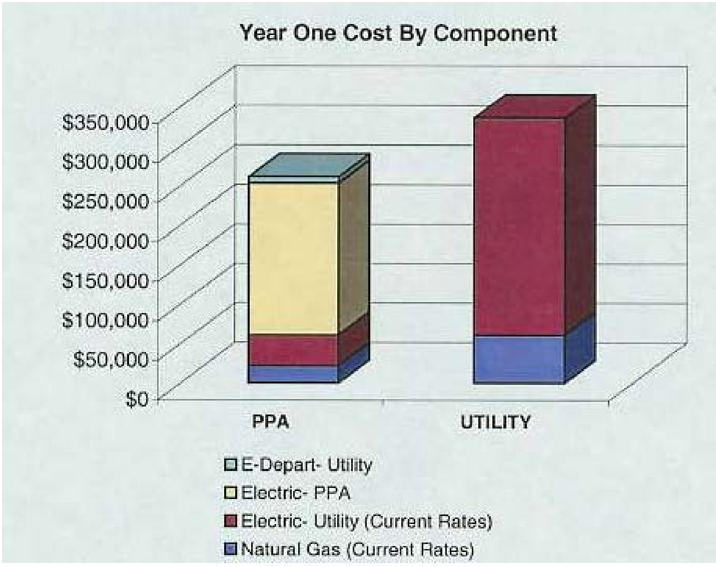

Figure 4: Aggregated Yearly Energy Cost Estimates Provided by BD Biosciences Pharmingen

Clarus Energy was unwilling to disclose their profit or loss in this project. They did, however, acknowledge that this was their first DER project and that they would like to use it to gain experience and publicity. Thus it was assumed that the developer was simply trying to break-even. The CPUC's Self-Generation Incentive Program[8, 9] reduced Clarus Energy's capital costs for this project by 30%, approximately $100,000.

BD Biosciences Pharmingen and Clarus Energy did provide performance data (*Appendix C: Data Provided by BD Biosciences Pharmingen* and *Appendix D: System Performance Data Provided by Clarus Energy*) for October through December 2002, the first three months of DER operation, which was useful in assessing the break-even assumption.

At current generation levels, Clarus Energy would sell approximately 1,500,000 kWh of electricity per year and could possibly sell up to 1,800,000 kWh annually. In this range, BD Biosciences Pharmingen's annual electricity payment to Clarus Energy would be approximately $140,000 to $170,000 and Clarus Energy would spend approximately $100,000 to $120,000 on natural gas[10]. Using DER-CAM cost estimates, Clarus Energy would spend an additional $8,000 on operation and maintenance of the equipment. Additionally, the amortized cost of the project costs (disclosed by Clarus Energy) would be approximately $33,000 annually. This analysis shows Clarus Energy profiting by $3,000 to $12,000 annually. The details of this analysis are provided in *Appendix E:*

[8] The Program offers a 30% rebate, up to $1,000/kW, on capital costs for natural gas CHP systems. CPUC Self-Generation Incentive Program July-December 2001 Status Report, http://www.cpuc.ca.gov/published/report/13690.htm

[9] San Diego Regional Energy Office, San Diego SELFGEN Program Frequently Asked Questions, http://www.sdenergy.org/docs/SELFGEN_FAQs.pdf

[10] Clarus acknowledged that they had a five-year fixed-price contract for natural gas. It was assumed that the contract price of natural gas was the utility cost of natural gas current to the time of the Clarus Energy's project implementation.

Economic Calculations Based on Data From Clarus Energy. While these figures are approximate, they do confirm the assumption that Clarus Energy was not primarily motivated by margin in this project.

5.2 Engineering Analysis

5.2.1 Site Energy Loads

Bob Schultze was able to provide Clarus Energy with detailed electricity usage data at 15-minute intervals, which SDG&E provides for its digitally metered customers. Heating data was more difficult to come by which is a typical problem for analyses of small scale CHP. Schultze only had records of monthly natural gas bills, and those bills include natural gas consumed for water heating and industrial heating needs as well as space-heating. He provided Clarus Energy with an estimate of the space-heating load, which has proved to be quite accurate in the first months of DER operation. His accuracy in this instance is a good indication of Schultze's excellent understanding of the site's energy consumption patterns.

Currently, the site's manufacturing facility has a 200-300 kW base electricity demand, a 500 kW peak, and has a peaky demand profile due to its nine-to-five manufacturing schedule. A 4 GJ (4 million BTU) capacity boiler is used for space heating. Two 0.55 MW boilers provide medium pressure steam to meet the facility's hot water needs. Another small boiler is used for industrial heating needs during working hours. Daytime cooling loads average 150 kW from June through October, and are negligible the rest of the year.

5.2.2 Backup Generation

The site has a 350 kW diesel backup synchronous generator, with twelve hours of diesel fuel storage, which is sufficient to cover critical loads, such as refrigeration, but is not sufficient to keep the manufacturing facility operating. Backup diesel engines may be operated only 52 hours per year (aside from during black-outs) in San Diego. The diesel engine operates one hour each week for testing. Diesel storage presents a potential hard upper limit to backup generation because supplier contracts to provide filling services as frequently as needed may be impossible in a large-scale disaster.

5.2.3 DER System Design

Clarus Energy designs their CHP systems around the heating loads of the site based on experience that recovered heat is what makes DER potentially profitable. Using proprietary software, Clarus Energy performed an analysis of the benefits considering the load information Schultze provided, technology performance specifications, and utility tariffs. Once Clarus Energy had determined that they could provide electricity at a lower $/kWh price than the utility, they performed a more detailed on-site analysis to further determine physical and logistical feasibility.

Clarus Energy chose to install two 150 kW natural gas induction generators packaged by Coastintelligen. Heat from the engines is recovered both from the exhaust and from the jacket liquid circulation loop. Maintenance is done during off-peak hours to avoid large on-peak demand charges and as required under the CPUC Self-Generation Rebate Program agreement[11]. Net metering for non-renewable sources is not available, so the generators have load following capability to match electrical demand.

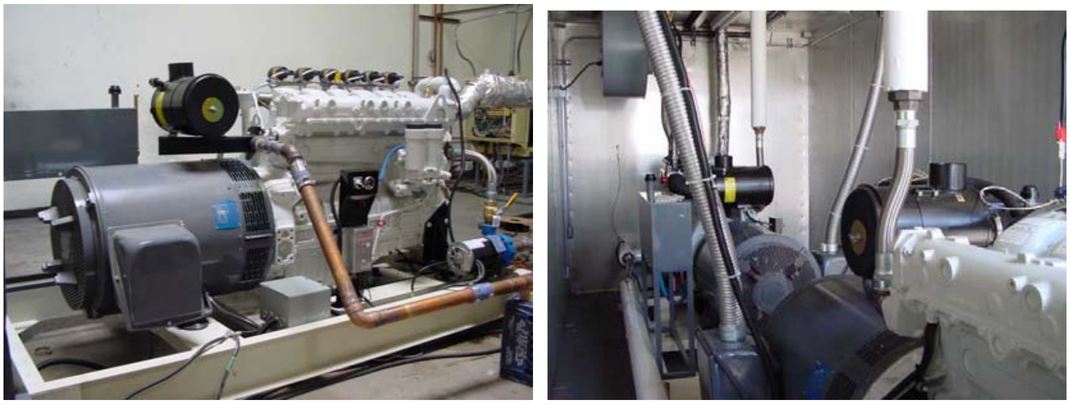

Figure 5: Coastintelligen's 150 kW Natural Gas Engine with Induction Generator (left) and the Two Engines Inside their Housing (right)

Excess heat captured from the generators is used in the building-heating loop and for building hot water. Due to the requirement to circulate fresh air continuously the building is continuously heated, except during warm summer days. For these same reasons, there is a small cooling load, which was not consistent enough to warrant the implementation of absorption cooling.

[11] To date, the servicing of the engines has not coincided with SDG&E's peak which triggers one demand charge. However, it *has* coincided with the site's peak-consumption which raises the second, 'non-coincident" demand charge. This can be seen in Figure 9, Peak Demand (Utility), in the month of November.

Figure 6: Heat Exchanger (left) and Boiler and Building Hot-Water Loop (right)

Figure 7: The Electric Chiller

Microturbine and photovoltaic (PV) systems were also considered for the site. In comparing microturbines to natural gas engines, Clarus Energy favored the percieved low cost and higher reliability of natural gas engines over microturbines. Although Clarus Energy noted that while reciprocating engines have higher maintenance costs required to obtain higher reliability, they are still more efficient and economical than microturbines. PV was quickly eliminated from consideration on the grounds that the site's location in the Torrey Pines area of San Diego gets at least some fog cover 80% of days.

5.2.4 Electricity Supply During Utility Blackouts

Utility power availability has been erratic, with outages that range from one minute to fourteen hours, and occurring about ten times a year. Reasons for power outages include scheduled down time for construction and upgrades; “Find-it-when-you-hit-it” accidents; fires; rolling blackouts; and other random events.

Induction generators require an alternating current (AC) electricity source in order to operate. Currently, the only source available at the site is the utility; therefore the natural gas engines could not be operated during a utility outage. However, the company and Clarus Energy are considering configuring their system so that the diesel backup generator could be used as the AC source required in the event of a utility outage. This would require the diesel engine to run continuously at a minimal level during the outage, and thus requires a continuous source of diesel fuel.

Another option for running induction generators in a stand-alone manner is through the use of capacitors and power electronics. Although experimentally proven (Nigim, 2000) for high quality power applications, this method has not yet been adopted by industry. This would be a promising development for the site because it would allow natural gas fired electricity generation during grid blackouts as long as natural gas was available, without requiring a continuous supply of diesel fuel.

Further research is needed to determine the technical requirements of these schemes and costs of implementation.

5.3 Utility Participation

SDG&E did not pose any barriers to this project, and while Clarus Energy saw some delay on the part of the utility involving the delivery and configuration of metering technology, the relationship has been quite smooth to date. Due to the site’s self-generation qualifying facility status, SDG&E offered the site a tariff absent of standby charges in exchange for higher demand charges.

California is one of the first states to have adopted interconnection standards for self-generating facilities. As such, SDG&E is enforcing Rule 21, Interconnection Standards for Non-Utility Owned Generation, which was updated in December 2000 to specify standard interconnection, operating, and metering requirements for DER. The required protective functions, such as voltage and frequency sensing equipment, circuit breakers and other interrupting devices, and other protective equipment required under Rule 21 added several thousand dollars to the cost of the project.

Figure 8: Digital Gas Meter Required for DER Systems by SDG&E

Both Clarus Energy and the site had positive impressions of SDG&E. Schultze acknowledged that SDG&E had often helped when it was not in the utility's best economic interest. He was also appreciative of the detailed electricity consumption data that SDG&E provides and their favorable customer service. Although SDG&E is losing electricity sales to the site, they are gaining natural gas sales to Clarus Energy; this might explain why SDG&E is more receptive to DER than many electricity only utilities.

5.4 Performance Data Reported by Clarus Energy

The DER-CAM analysis was performed using data provided prior to the actual installation of the DER system, allowing the DER-CAM team to examine this project through the eyes of the decision-makers. The DER system was installed during the summer of 2002 and became operational in October 2002. In January and February 2003 actual energy cost and usage data was provided (*Appendix C: Data Provided by BD Biosciences Pharmingen*) and Clarus Energy provided summary performance data (*Appendix D: System Performance Data Provided by Clarus Energy*). The DER system has performed as anticipated. This data was used in the economic analysis presented in *Appendix E: Economic Calculations Based on Data From Clarus Energy*.

The data provided by the site (Figure 9) summarizes project performance. The DER system is providing 70-80% of site electricity, 60% of space and water heating, and is saving the company about $4,500 monthly. In December, approximately 75% of savings were from natural gas savings. In the winter, heating loads are high and SDG&E's electricity rates are relatively low. In the summer months, however, the heating load will be lower, although electricity rates will be higher (*Appendix G: Summary of Tariffs* shows the summer and winter tariff schedules) so in the summer, more savings are expected from electricity and less from recovered heat.

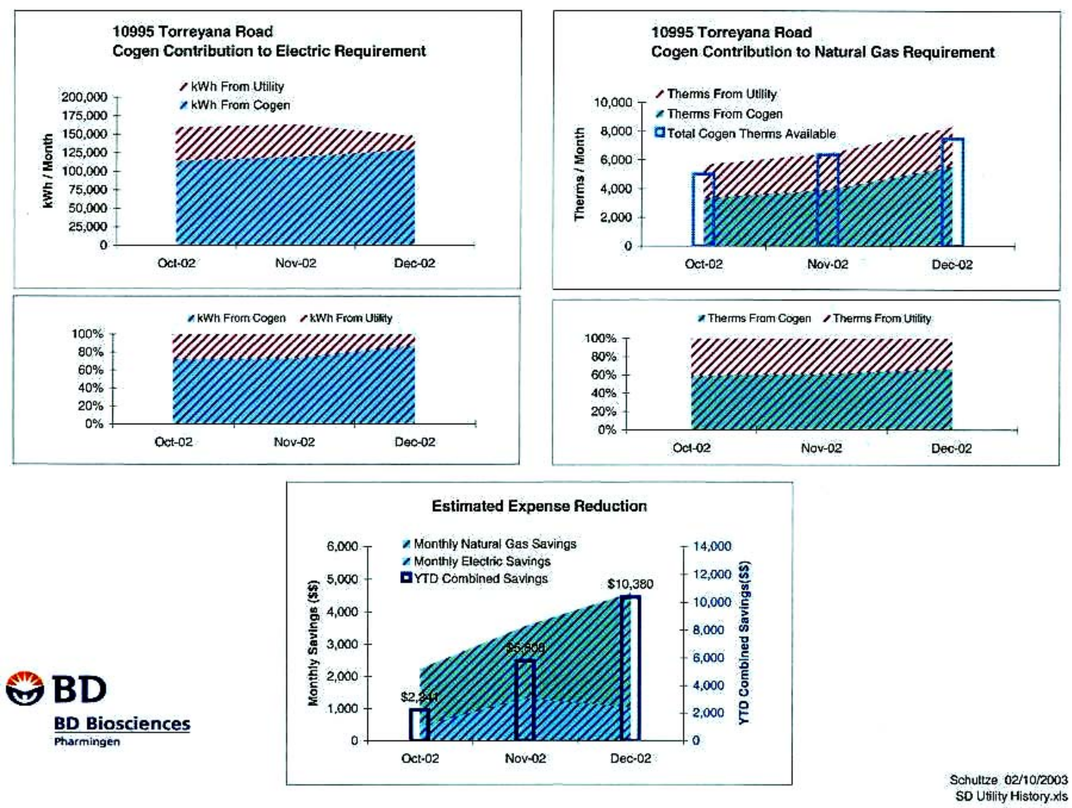

Figure 9: CHP Performance and Savings Summary Provided by BD Biosciences Pharmingen

5.5 Customer Loads

The monthly data SDG&E provides, along with some hourly profiles was combined with prudent assumptions to generate the hourly load profiles required by DER-CAM. The load profiles and the details of creating them are presented in *Appendix F: Development of Hourly Load Profiles.*

5.6 Market Information

Tariff information was gathered from SDG&E and is summarized in *Appendix G: Summary of Tariffs.*

5.7 DER Technology Information

Efficiency and heat recovery data for natural gas engines was collected from Coastintelligen specification sheets. Clarus Energy did not provide information on the alternative DER technologies they considered. Therefore, other DER technology information collected by the DER-CAM team for previous projects was used is and provided in *Appendix H: DER-CAM Technology Data*. This information includes economic and performance data for microturbines, natural gas engines, diesel engines, fuel cells, photovoltaics, heat recovery units and absorption chillers.

Due to their ability to make use of CHP with sufficient heat recovery, the site is considered a Qualifying Facility (QF). QF's are facilities that meet criterion set forth by the Federal Energy Regulatory Commission (FERC) for minimum efficiencies and other requirements for on-site power generation.[12] It is sometimes the case that standby charges are waived for QFs.

[12] FERC document 18 C.F.R. 292.203(a) specifies the requirements of a Qualifying Small Power Production Facility and document 18 C.F.R. 292.203(b) specifies the requirements of a Qualifying Cogeneration Facility. The formula for calculating system efficiency is

$$SystemEfficiency = \frac{Electricity\,\mathrm{Pr}\,oduced\,(kWh) + \tfrac{1}{2}\,Utilized\,\mathrm{Re}\,capturedHeat\,(kWh)}{FuelEnergyConsumed\,(kWh)} \times 100\%$$

6. DER-CAM Results

After developing the BD Biosciences Pharmingen data into the necessary inputs, DER-CAM was used to validate the model and to examine cases and sensitivities of interest.

6.1 Cases

Five standard cases were established that modeled potential decisions with the goal of obtaining insight into the decision-making. Table 2 is a summary of these cases and Sections 6.1.1 through 6.1.5 discuss the individual cases in detail. Section 6.1.6 presents and discusses the results of these cases.

Table 2: Description of the Five DER-CAM Cases

Case 1	Base Case Utility purchase of all electricity and gas
Case 2	Unlimited Installation of DER Technologies Any technology and capacity combination allowed (true optimization)
Case 3	Choice of Only Natural Gas Engines Only the technology that Clarus Energy chose is available with no requirement to install or any capacity constraint.
Case 4	Choice of Only 150 kW Natural Gas Engines This is the unit capacity that Clarus Energy chose.
Case 5	Forced purchase of two 150 kW Natural Gas Engines with Heat Recovery This forces the system design that Clarus Energy chose.

6.1.1 Case 1: Business as Usual

Case 1 uses DER-CAM to estimate annual energy expenses if the site purchases all of its electricity and natural gas from SDG&E. This case is used to ensure that load profiles and tariffs are acceptably accurate and that DER-CAM's accounting of utility bills is correct.

6.1.2 Case 2: Unlimited Installation

Case 2 allows for theoretical energy cost minimization by allowing the model to choose from all the technologies in its database (see *Appendix H: DER-CAM Technology Data*). This case utilizes DER-CAM to its full potential, with no restrictions on technology choices or investment levels. The results of Case 2 represent the optimal set of technologies that minimize annual energy costs.

6.1.3 Case 3: Unlimited Installation of Natural Gas Engines

Case 3 restricts the model to choosing natural gas engines, the technology that Clarus Energy chose to install. However, the size and number of engines is not restricted. Also, natural gas engines can be selected for purchase as engines only, engines with heat recovery (CHP), engines with absorption chillers, or engines with CHP and absorption chillers.

This case acknowledges that many DER developers have a specific technology in mind when they consider a project, which reduces the system design problem to choosing optimal generating capacity and optimal use of recoverable heat. Developers consider many factors that DER-CAM does not, including:

- ***Value of Proven Technology***: certain technologies such as fuel cells and microturbines are still immature.
- ***First Hand Experience***: Developers will be more comfortable designing a system using familiar technologies. Conversely, developers may have had negative experiences or witnessed unsuccessful projects with particular technologies.
- ***Non-economic Benefits***: Certain technology characteristics do not have a direct economic cost or value, yet may play heavily into decisions. These characteristics include noise, footprint, environmental impact, water requirements, ease of permitting, ease of installation, ease of operation and maintenance, and interest in supporting an emerging technology.

6.1.4 Case 4: Forced Purchase of Clarus Energy's Choice Technology

Case 4 requires the DER-CAM to install only 150 kW natural gas engines. As an extension of Case 3, Case 4 additionally acknowledges that developers may prefer a specific unit size, and seeks the economically optimal number of these units to install, as well as the economically optimal use of recoverable heat.

6.1.5 Case 5: Mimicking Clarus Energy's System Design

Case 5 forces DER-CAM to make the same system design choice as Clarus Energy: two 150 kW natural gas engines with CHP. This case estimates the annual energy costs that the company will experience with DER adoption. Using this case as a validation of DER-CAM was not possible because Clarus was unwilling to provide an estimate of their profit from this project. Clarus did acknowledge that this project was done more to get a "foot in the door" than to profit directly. Thus, it was assumed that Clarus Energy was forgoing profit from this project and providing the DER system to the site at cost. The latter company did provide an estimate of their annual energy savings, which are therefore assumed to be the total economic benefit of the project. This case is then used to study post-installation sensitivities of annual operating cost to changes in electricity prices, gas prices, standby charges, competitive transmission charges, or demand charges.

6.1.6 Results from DER-CAM Cases

Table 3 presents the DER-CAM annualized results for the five cases considered. Figure 10 presents these results graphically.

Table 3: Results from DER-CAM Cases

CASE	**Technologies Selected**	**Annual Energy Cost**	**Percentage of Case 1 Cost**	**Annual Savings Over Base Case**	**Electricity Purchases**	**Natural Gas Purchases (including purchase for engines)**	**Self Generation Costs (capital costs of equipment plus maintenance)**	**FERC Qualifying Cogeneration Facility Efficiency**
1: No invest		$ 333,733	100%		$ 273,085	$ 60,648	$ 0	
Site's estimate of annual energy Costs without DER		$ 315,000			$ 260,000	$ 55,000	$ 0	
2: Unlimited invest	1x 500 kW nat. gas engine with CHP	$ 219,614	66%	$ 114,119	$ 522	$ 147,171	$ 71,921	40.7%
3: Unlimited invest in nat. gas engines	1x 500 kW nat. gas engine with CHP	$ 219,614	66%	$ 114,119	$ 522	$ 147,171	$ 71,921	40.7%
4: Forced minimum investment in 150 kW nat. gas engines (gen. only)	3x 150 kW nat. gas engine	$ 246,661	74%	$ 87,073	$ 5,012	$ 163,762	$ 77,886	31.8%
4: Forced minimum investment in 150 kW nat. gas engines with CHP	3x 150 kW nat gas engine with CHP	$ 223,832	67%	$ 109,901	$ 1,462	$ 151,657	$ 70,714	38.7%
4: Forced minimum investment in 150 kW nat. gas engines (gen. Only) and 150 kW nat. gas engines with CHP	1x 150 kW nat gas engine, 2x 150 nat. gas engine with CHP	$ 226,447	68%	$ 107,287	$ 1,462	$ 151,662	$ 73,323	38.7%
5: Forced duplication of site decision: 2x 150 kW nat. gas engines with CHP	2x 150 kW nat gas engines with CHP	$ 233,996	70%	$ 99,737	$ 35,234	$ 144,374	$ 54,388	39.2%
Pharmingen/Clarus Energy DER System	2x 150 kW nat gas engines with CHP	$245,000	Pharmingen estimate of annual savings: $70,000. This is 78% of their no-invest costs		$ 47,500	Estimated together by Pharmingen: $197,500		

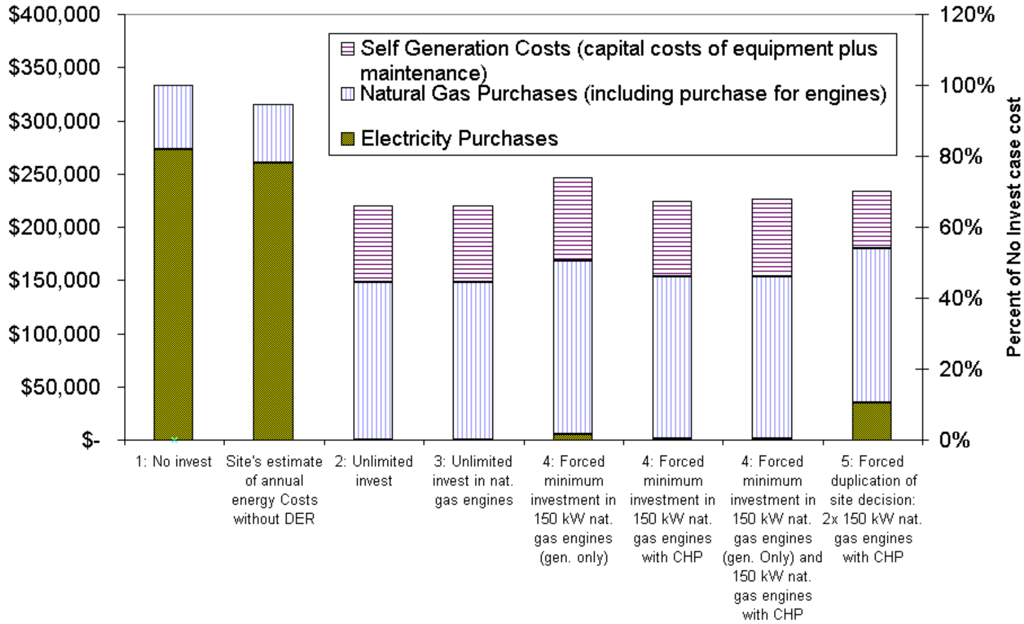

Figure 10: Graphical Depiction of DER-CAM Case Results

6.1.7 Discussion of DER-CAM Cases Results

Cases 1, 2, and 5 were used as model validation as discussed earlier in Section 6.1. Table 4 is a summary of the validation results.

Table 4: Summary of Validation Results

Validation Consideration	DER-CAM	Site	Percent Difference
Yearly Energy Costs Without DER (Case 1)	$334,000	$315,000	6%
Yearly Energy Costs With 2 x150 kW Natural Gas Engines with Heat Recovery (Case 5)	$234,000	$245,000	-4%
Yearly Energy Savings With 2 x150 kW Natural Gas Engines with Heat Recovery (Case 5)	$100,000	$70,000	43%
Economically Optimal Amount of DER Capacity to Install (Case 2)	500 kW of natural gas engine capacity with heat recovery	300 kW of natural gas engine capacity with heat recovery	67%

The DER-CAM analysis confirmed the financial estimates provided by BD Biosciences Pharmingen and assuming Clarus Energy's break-even strategy. DER-CAM reports an annual energy cost of $334,000 without DER investment and $245,000 with the Clarus Energy installed system consisting of two 150 kW natural gas engines with CHP. This is an energy cost reduction of 30%.

According to DER-CAM, greater savings could be realized by investing in a larger DER system: DER-CAM's optimal solution was the purchase of a 500 kW natural gas engine with CHP, which would lead to a cost reduction of 34%. If only 150 kW natural gas engines were an option, DER-CAM still shows that an additional $10,000 in annual savings over the Clarus Energy system could be realized by installing a third generator. The discrepancy between DER-CAM's economically optimal technology selection (Case 5) and Clarus Energy's is discussed in detail later in this section.

It is interesting to note that for Case 1, the majority of energy expense is from electricity purchase from SDG&E. However, all DER-CAM Case results where investment is allowed switch the majority of energy purchase to natural gas. Clarus Energy was able to obtain long-term natural gas contracts, which assure price stability for the site because they purchase little electricity from SDG&E. This is a powerful benefit of DER during the current period of energy price instability.

Another point of interest in comparing DER-CAM's optimal system (Case 2 – 500 kW capacity) with Clarus Energy's (Case 5 - 300 kW capacity) is that DER-CAM selected a system that was capable of meeting nearly all of site electricity demand, while Clarus Energy selected a system capable of meeting the base-load electricity demand. Utility connected DER systems tend to be matched to base-load demand because DER is most profitable when equipment is running at rated power most of the time i.e. has a high capacity factor. Furthermore, economics of scale ensure the cost per kWh of DER falls as systems get larger. Thus, the return is largest for a system designed to match base-load demand but the most profitable system can be larger. However, these rules of thumb are suboptimal in an economic sense because the system should be chosen to minimize overall cost and not to minimize levelized cost. One of the drivers of the DER-CAM solution that much more electricity should be generated than the chosen system is capable of is the high value of electricity, especially in the summer.

In Figure 10, note that while the total cost results, i.e. total height of the bars, do not differ dramatically, the composition of costs does. In all DER cases, 2 through 5, electricity purchases are minimal. They are only significant in the small installed capacity case 5. This pattern shows that results are driven by the electricity side, and not the heat side, i.e. the systems are sized to meet the electricity requirements at the site. This result is reasonable given that electricity is expensive, especially on peak, but is nonetheless counter to a common rule of thumb that systems should match heat loads and opportunistically generate electricity.

Appendix I: Net Present Value and Internal Rate of Return Analyses demonstrates how varying economic criteria and business perspectives can affect optimal DER specifications and gives insight into the discrepancy between DER-CAM solutions and Clarus Energy solution. Included in this appendix is an analysis of the DER project from the business perspective of Clarus Energy, which accepted the upfront capital costs of the project and receives income from electricity sold to the site. From this perspective, smaller systems become more attractive. For large installed capacity, some capacity gets used only infrequently. It is not profitable for Clarus Energy to receive payment for only the electricity from this larger capacity, while it is profitable to the site if value is also placed on the recovered waste heat from this capacity.

As DER is not yet common, it could be further hypothesized that businesses tend to hedge their bets on profit. They invest enough to see a profit from their investment, but do not completely buy into DER in case it is not as profitable as anticipated. The tendency for actual DER development to be smaller than the economically optimal solution was seen in four of the five site studies from Bailey *et al* (2003). In the fifth site study, DER-CAM selected the same amount of capacity as the site.

Two other possible sources of discrepancy between DER-CAM results and the site choice are the following. First, the cost data used may be inaccurate and the 500 kW generation may be given an unfair advantage as a result. Second, having multiple small units has a reliability advantage that DER-CAM is not considering. Large numbers of smaller generators results in a more reliable system. This could be quite important when demand charges are high.

6.1.8 DER-CAM Solutions Fail to Meet FERC Qualifying Cogeneration Facility Efficiency

In all of these results, it should be noted that DER-CAM included CPUC subsidies in all DER systems that included heat recovery (see Section 5.1). However, operation schedules selected by DER-CAM did not lead to heat recovery great enough to meet minimum efficiency requirements under FERC's QF definitions. Ineligibility for CPUC subsidies would increase Case 2 annual energy costs to $242,000 (72% of Case 1 costs) and Case 5 annual energy costs to $246,000 (74% of Case 1 costs). For a given technology selection's cost estimates with and without the CPUC subsidy, the site could decide if running its generators less to increase the overall efficiency of the system was more cost effective than disregarding the CPUC subsidies and operating without efficiency constraints.

6.2 Sensitivities

Sensitivity analyses were preformed on the cost of natural gas and on standby charges. In addition, the net cost of electricity, including energy, demand, time of use, and standby charges, was converted into a flat $/kWh energy charge for all hours. Inplementation of these sensitivities are described below and results follow in Section 6.2.4.

6.2.1 Spark Spread Sensitivity

Spark spread is here defined as the ratio of cost per unit energy of electricity to the cost per unit energy of gas. A large spark spread implies energy purchase in the form of electricity is much more expensive than energy from natural gas. When the cost of electricity is high enough relative to that of natural gas (large spark spread), self-generating electricity using natural gas becomes attractive. In this sensitivity, by varying the natural gas costs, the spark spread is varied.

6.2.2 Standby Charge Sensitivity

Standby charges are often imposed on DER adopters as a monthly fee per kW of DER capacity. This charge is intended to make self-generating sites pay for the excess capacity that the utility must, in principle, have on hand to cover load when on-site DER equipment is not operating. Sensitivities to standby charges were done to see what affect standby charges may have had on BD Biosciences Pharmingen's decision to self-generate.

It should be noted that standby charges have the same effect as increasing the capital cost of equipment *i.e*. they are a fixed annual cost per kW of capacity. Every dollar of monthly standby charge per kW of capacity translates into $12 annually per kW of capacity. This is equivalent to a $95/kW increase in capital costs, assuming a 12.5 year lifetime of equipment and a 7.5% interest rate. The cost of equipment, engineering evaluation, and installation of a 150 kW natural gas engine including heat recovery is $883/kW in DER-CAM. Capital costs of natural gas engines and other generation technologies considered in DER-CAM can be found in *Appendix H: DER-CAM Technology Data*.

6.2.3 Flat Rate Electricity Sensitivity

The application of time of use (TOU) electricity rates and demand charges has been the traditional method for utilities, including SDG&E, to apply limited time differentiated pricing to a commodity that, historically, was too expensive to meter in real-time. Together with demand charges, this creates a peaky rate schedule, often peakier than would result from actual real-time pricing based on day ahead market prices. For this reason, the opposite extreme, flat electricity rates (same cost per kWh at any time and no demand charges), was applied to the model. The flat rate ($0.15/kWh) was determined by dividing BD Biosciences Pharmingen's total annual electricity costs ($260,000) prior to DER installation to their total electricity consumption (1,700,000 kWh) prior to DER installation.

6.2.4 Results And Discussion of Sensitivity Analyses

6.2.4.1 Spark Spread

Figure 11 below shows the spark spread sensitivity results derived by varying gas prices between half and twice their actual price in this study. Each bar represents the installed capacity of natural gas engines with CHP chosen by DER-CAM for a different spark spread. The horizontal line depicts the maximum electric load of the site so that installed capacity can be compared to maximum demand. The other line plotted on the graph is the yearly energy cost (the sum of DER capital and operating costs and electricity and gas purchases) with respect to the vertical axis on the right side of the graph.

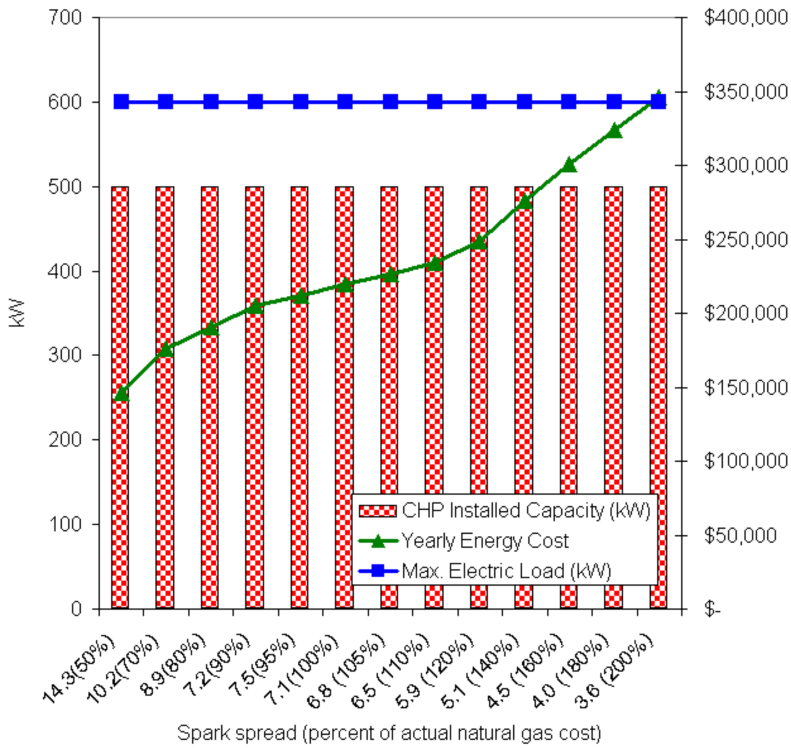

Figure 11: Spark Spread Sensitivity

In the spark spread range presented in Figure 11 below, from 14.3 (where gas costs are decreased by 50% while grid electricity prices are held constant) to 3.6 (where gas costs are increased by 200% while grid electricity prices are held constant), DER-CAM chose one 500 kW engine with CHP for every spark spread considered, with yearly energy costs ranging from $150,000 to $350,000. Furthermore, the amount of installed capacity is nearly enough to meet all of peak site electricity demand. These results suggest the site is better off generating most of their own electricity even if natural gas prices were to double.

To understand the robustness of the DER-CAM solution, note that as the gas price is increased, the benefit of the waste heat recovery rises, even though electricity tariffs are held constant. If natural gas prices actually rose significantly, this would also be reflected in electricity prices, eventually. This robustness of the chosen technology in this sensitivity reveals one of the less obvious attractive features of DER with CHP.

6.2.4.2 Standby Charge

Figure 12 below shows the standby charge sensitivity results. Bars are similar to those for the spark spread sensitivity graph (Figure 11) in that each one represents DER-CAM's chosen installed capacity of natural gas engines with CHP for a given standby charge ($/month). In this sensitivity, all capacity selected by DER-CAM is reciprocating engines with CHP. The horizontal line depicts the maximum electric load of the site so that installed capacity can be compared to peak on-site demand. The other line plotted on the graph is the yearly energy cost also as in Figure 11.

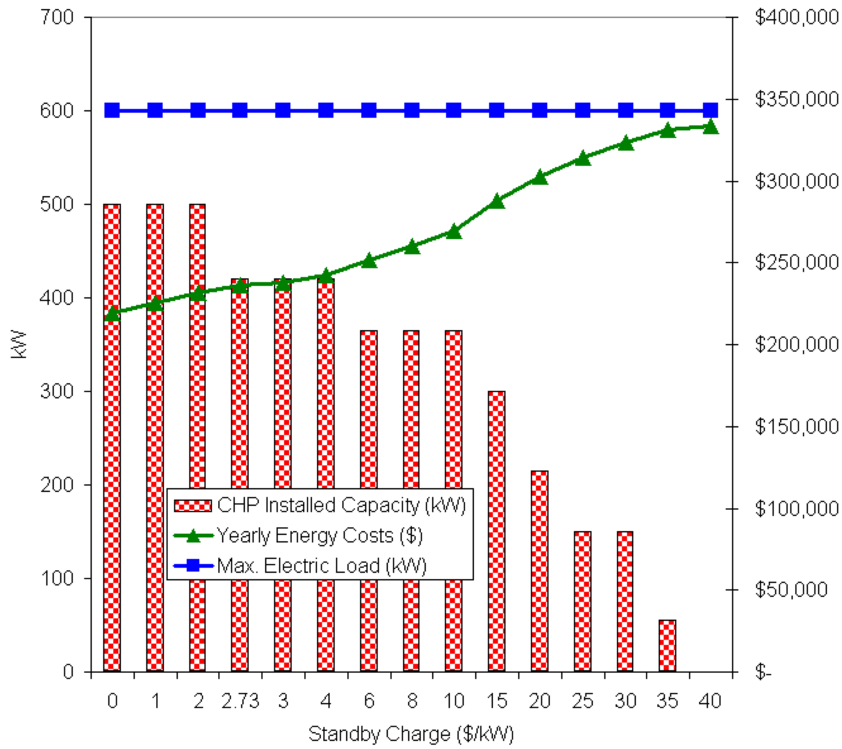

Figure 12: Standby Charge Sensitivity

Standby charges of $2/kW-month and less do not affect the level of CHP capacity installed. CHP capacity installed gradually decreases as standby charges rise above $2. DER becomes entirely uneconomic when monthly standby charges exceeds $35/kW-month.

Current SDG&E standby charges are $2.73/kW, and many distribution companies have significantly higher rates. These rates can clearly affect a site's DER adoption decision. Qualifying Facility status does sometimes allow DER adopters to opt for a tariff structure without standby charges, as the site did. However, demand charges are increased if this option is chosen, which penalizes qualifying facilities heavily if their equipment is offline during times of significant electricity load.[13]

[13] Being a Qualifying Facility (QF) makes BD Biosciences Pharmingen eligible for the time of use (TOU) schedule AL-TOU-DER, which is the same schedule as AL-TOU (the general TOU schedule) except that it excludes the standby charges defined in Schedule S. Accepting the QF schedule, however, results in a larger demand charge should their self-generation capacity be compromised and the full electricity load of the site be drawn from SDG&E. For tariff schedules, see: http://www.sdge.com/tariff/

6.2.4.3 Flat Rate Electricity Tariff

Figure 13 below shows the results of the DER-CAM flat electricity rate sensitivity. Bars represent the total yearly energy cost as defined above, which are broken into proportions of the three costs. Points on the line depict the level of installed capacity chosen by DER-CAM in each case.

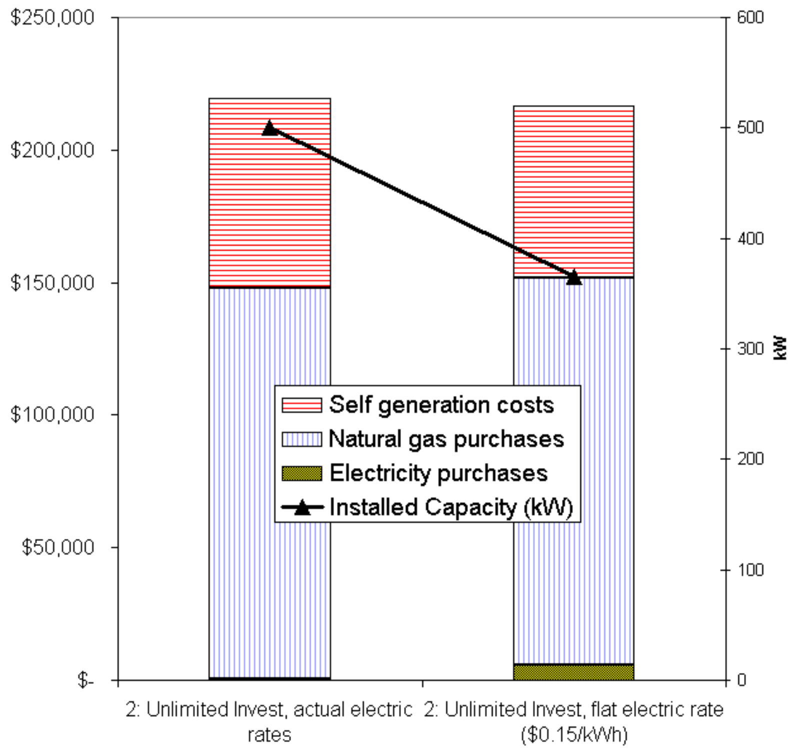

Figure 13: Flat Electric Rate Sensitivity for BD Biosciences Pharmingen

A flat rate electricity tariff of $0.15/kWh decreases installation by 27% (365 kW instead of 500 kW for current tariff structure). The capacity chosen for flat rate structures is much closer to site base-load demand. Peakier tariffs encourage larger DER installations because suppression of peak loads that coincide with peak charges is more valuable than in the flat tariff structure. This sensitivity emphasizes the importance of addressing time-of-day prices rather than assuming an average electricity price when designing DER systems.

7. Conclusions

7.1 Conclusions from Business Case Analysis

At the BD Biosciences Pharmingen site, annual energy costs have to date been reduced by 30% by installing a DER system, and the analysis completed here suggests savings up to 34% may have been possible. DER has proven successful in lowering energy costs while reducing exposure to energy cost increase and volatility.

Overall, the BD project does not deliver exceptional savings, given the risks of adapting an unfamiliar technology. However, the benefits to BD are appealing given the absorption of most risk by Clarus Energy. It should also be noted that BD's low load factor and moderate energy loads did not make this project a promising DER candidate ex ante.

7.2 Limitations of this Analysis

BD Biosciences Pharmingen and Clarus Energy were naturally reluctant to provide financial details that may provide their competitors with information on their operations and facilities. Most limiting was the lack of information on Clarus Energy's profit or loss in this project, without which the actual project economics cannot be precisely ascertained. In its place, the working assumption was made that Clarus Energy merely broke-even on this project in order to enter the DER system development market.

Many additional assumptions had to be made at various points in the analysis. These assumptions are described in detail in *Appendix B: Assumptions Made in DER-CAM Modeling*. One significant limitation of this analysis was that DER systems were assumed to receive CPUC subsidies for any generation technology with heat recovery if they *could* meet FERC QF efficiency requirement, regardless of if they actually utilized enough heat in the operation schedule selected by DER-CAM. As seen in the results, DER-CAM optimal schedules did not lead to FERC-defined system efficiencies of 42.5% or greater. For the DER-CAM selected systems, the site would have to decide if it was more cost effective to disregard the CPUC subsidies or to limit the operation of the generators in order to improve the heat recovery efficiency.

While improved electricity reliability was desired at the site, the installed DER system would need to be modified before it could offer this. The actual costs to the site of utility blackouts remains to be known. Under these circumstances, the cost and value of improved power reliability could not be considered.

8. References

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Appendix A: DER-CAM at the Berkeley Lab

All DER research efforts at Berkeley Lab have focused on small-scale on-site generation (i.e. < 1MW), especially those installations involving combined heat and power (CHP) applications. While the 1 MW limit is somewhat arbitrary, it represents a reasonable size above which generation could be big enough to be installed under existing PURPA rules and typical ISO rules for participation in wholesale electricity and ancillary services markets, which typically specify a minimum size of 1 MW.

A major recent enhancement to DER-CAM was addition of thermal energy modeling to modeling of electrical energy. This enhancement involved many assumptions and modeling difficulties, but resulted in the ability to jointly optimize power generation with CHP systems. DER-CAM was then further developed through integration with Geographical Information Systems (GIS) (Edward *et al* (2002)), and applied to the modeling of a hypothetical microgrid in San Diego that was based on a collection of businesses in that city (Bailey *et al* (2002)). DER-CAM is also capable of analysing emissions studies, as reported in Marnay *et al* (2002), where the authors studied the effects of a carbon tax on the adoption of DER technologies.[1]

DER-CAM has also proven to be a viable tool for sensitivity analysis. In the study of the hypothetical San Diego microgrid, the effects of varying parameters thought influential on DER technology adoption were studied. The results were surprising in that the level of standby charges, often cited by people within the DER industry to be the biggest hurdle to technology adoption, were not particularly powerful. Other factors, such as electricity and gas prices were determined to be more important at influencing the technology adoption decision.

Analysis of test sites allowed for collection of useful input data for DER-CAM and comparisons of results to the financial analysis performed by each site. This study in part grows out of the case studies project. The technology adoption decision itself could also be compared to DER-CAM’s choice of the least-cost technology installation and operation.

The Distributed Energy Resource-Customer Adoption Model

DER-CAM is a cost minimization mixed integer program formulated in GAMS[2] (General Algebraic Modeling System) and solved with CPLEX. It has a Visual Basic front end, developed internally by the Berkeley Lab DER-CAM team, permitting ease of data and parameter entry.

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[1] Marnay et al. “Effects of a Carbon Tax on Combined Heat and Power Adoption by a Microgrid,” presented at the Second International Symposium on Distributed Generation, Stockholm, Sweden. October 2-4 2002.

[2] GAMS is a proprietary software product used for high-level modeling of mathematical programming problems. It is owned by the GAMS Development Corporation (http://www.gams.com) and is licensed to Berkeley Lab.

The objective function to be minimized is the annual cost of providing energy services to the site, through either utility electricity and gas purchases, or DER operation, or a combination of both. This value is a summation of costs for electricity purchases, gas purchases, capitalized costs of DER equipment, and operating and maintenance costs.

Typical inputs to the model include the site's five load profiles, tariff structure under which the site buys electricity and other fuels, and values from a database of technology costs and performance. The five load profiles are electricity-only (not including cooling), cooling, space heating, water heating, and natural gas only. The output is a set of installed DER technologies that minimize annual costs of meeting energy demand for the site, an hourly operating schedule of each selected technology, and utility energy purchases.

A key constraint i.e. condition to be met is that energy demand for each hour must be met by the purchase of energy from utilities, operation of any technology or set of technologies selected by the model, or a combination of purchase and on-site generation. In addition, some environmental rules must be obeyed, and equipment capabilities must not be exceeded.

The model's inputs and outputs are depicted graphically in Figure 14 below:

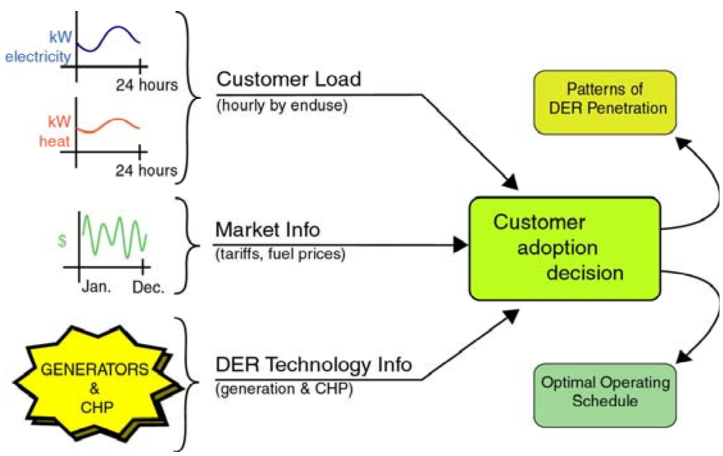

Figure 14: Graphical Depiction of DER-CAM

Appendix B: Assumptions Made in DER-CAM Modeling

This section covers the general assumptions inherent in using DER-CAM.

All information collected is concurrent: loads, technology options, tariffs are all from the same time, as far as possible.

DER-CAM uses the same information as developers: all technology cost and performance data is perfect and known by all the decision makers involved in the process.

Configuration of selected technologies is not variable: All thermal technologies in the model have one of four configurations: electricity only, DG with CHP capability, DG with absorption chiller capability, or DG, CHP, and absorption cooling capability. Each technology is simply a "box" that produces one of the four combinations of electricity, heat, and cooling capacity each hour with representative costs. In reality, the actual systems may not be able to be integrated without additional electrical and mechanical equipment. The integrated packages included in the model represent only a few of the many combinations of CHP technologies possible.

Standard technologies such as furnaces and electric chillers pre-exist on site: DER-CAM estimates the cost of a DER systems that might include CHP or absorption chilling. In the cases, the CHP systems were considered retrofits to the existing heating and cooling systems in each building. However, the capital cost of a DER system with CHP or absorption chilling, dollars per kW, was estimated based on knowledge of the installed cost of these systems from some of the sites where that particular information was available. It is assumed that each customer uses a natural-gas-fired boiler or furnace to meet residual heating loads, and a compressor driven air conditioning system is used to meet residual cooling loads. It is assumed this equipment for meeting residual loads operates at average efficiency.

Technology performance remains constant at varying capacity: Since typically the performance of the CHP systems is often given only at maximum capacity in specification sheets, it was assumed that each CHP unit operated at constant efficiency and COP over the range of output. That is, the amount of heating or cooling a unit produced was proportionally related to the percent of electrical capacity the unit is producing. The ratio of heating output, or cooling output, per unit of electric output is also assumed fixed. In other words, the efficiency of fuel input and energy outputs per unit of electricity production capacity are assumed fixed.

Technology data obtained from manufacturers and developers is accurate: The manufacturer performance specifications are assumed to be correct and the price estimates that the DER-CAM team has gathered from retailers and developers are assumed to be representative for the area and time period studied. Capital costs considered are those of technology purchase, system design, and system installation.

There is no quantifiable financial value to energy reliability: DER-CAM does not account for the value of electric reliability. If this benefit of DER were quantifiable and accounted for, DER would appear more attractive. Conversely, the affect of imperfect reliability will increase demand charges and would make DER appear less attractive.

Heat from all recoverable heat and heating loads is of the same quality: Heat flow is modeled using kW (power) on an hourly basis. Heat is all the same quality, it flows where it is directed to, with no losses (heat is delivered with 100% efficiency to loads). The temperatures, flow rates, and pressures of the heat transfer mediums are ignored. The specific type and capacity of the thermal end-use, temperatures, flow rates, distances, pressures, efficiency curves, become important in specific applications but were not included in this model. For example, the inlet temperatures of the hot water (cooling loop) or the chilled water (absorption cooling) are assumed to be ideal.

Systems qualify for subsidies that they are eligible for*:* In DER-CAM, subsidies are reflected in capital costs of DER equipment, regardless of how the DER equipment is actually used once it is installed. However, operation schedules selected by DER-CAM may not in fact lead to system performance that justifies these subsidies. For example, BD Biosciences Pharmingen was eligible for CPUC subsidies on any natural gas generation equipment with heat recovery, provided it met FERC QF efficiency requirements. DER-CAM assumes that these requirements are met in assigning capital costs to the project, yet may select to operate the system with heat recovery below the amount required to maintain the FERC QF minimum efficiency requirements.

DER equipment is able to maintain a load-following capability: DER equipment is assumed to respond with negligible delay to variations in load or dispatch. In reality, quantifiable response times will be required and would necessitate electrical and thermal storage elements in order to behave as the DER-CAM model implies.

Electric loads of absorption chillers are ignored: This is a reasonable assumption because a standard absorption cooling system contains only two water pumps: Pumping a liquid requires substantially less energy than a compressor.

No thermal storage exists: The constraints to meet heating and cooling load with production has to be met instantaneously for each hour of the day. In other words, the building does not have thermal mass and cannot "inventory" heat from one hour to the next, nor can thermal reservoirs (such as a water tank) be used to store heat or cooling for later use. However, heating and cooling loads can be reduced during off peak hours to reflect the reduced demand for energy at those times.

Parameters assumptions used in DER-CAM.

- Recoverable heat from generation equipment is converted to useful heat (via a heat exchanger) at an efficiency of 0.8.
- Purchased natural gas is converted to useful heat at an efficiency of 0.8.

- Electric chillers have a coeffient of performance (COP) of 5 and absorption chillers have a COP of 0.7.
- The technology lifetimes are considered to be 12.5 years for all technologies except photovoltaics, which are assumed to last for 20 years.
- Discounting cash flows to the present value is done at a nominal interest rate of 7.5% unless the specific interest rate used in the calculations at a particular site is known (it was not at BD Biosciences Pharmingen).

Operation of Diesel Engines is limited to 52 hours per year. This limit was used for any diesel engines the site chose to install as part of their DER system. For modeling purposes, the diesel engine on site prior to the Clarus Energy system installation was not considered. Regulations will vary with by air quality management district. Typically, fixed diesel generators can only be used during an outage, a declared emergency, or for a limited testing period. Mobile diesel generators are usually not restricted.

Appendix C: Data Provided by BD Biosciences Pharmingen

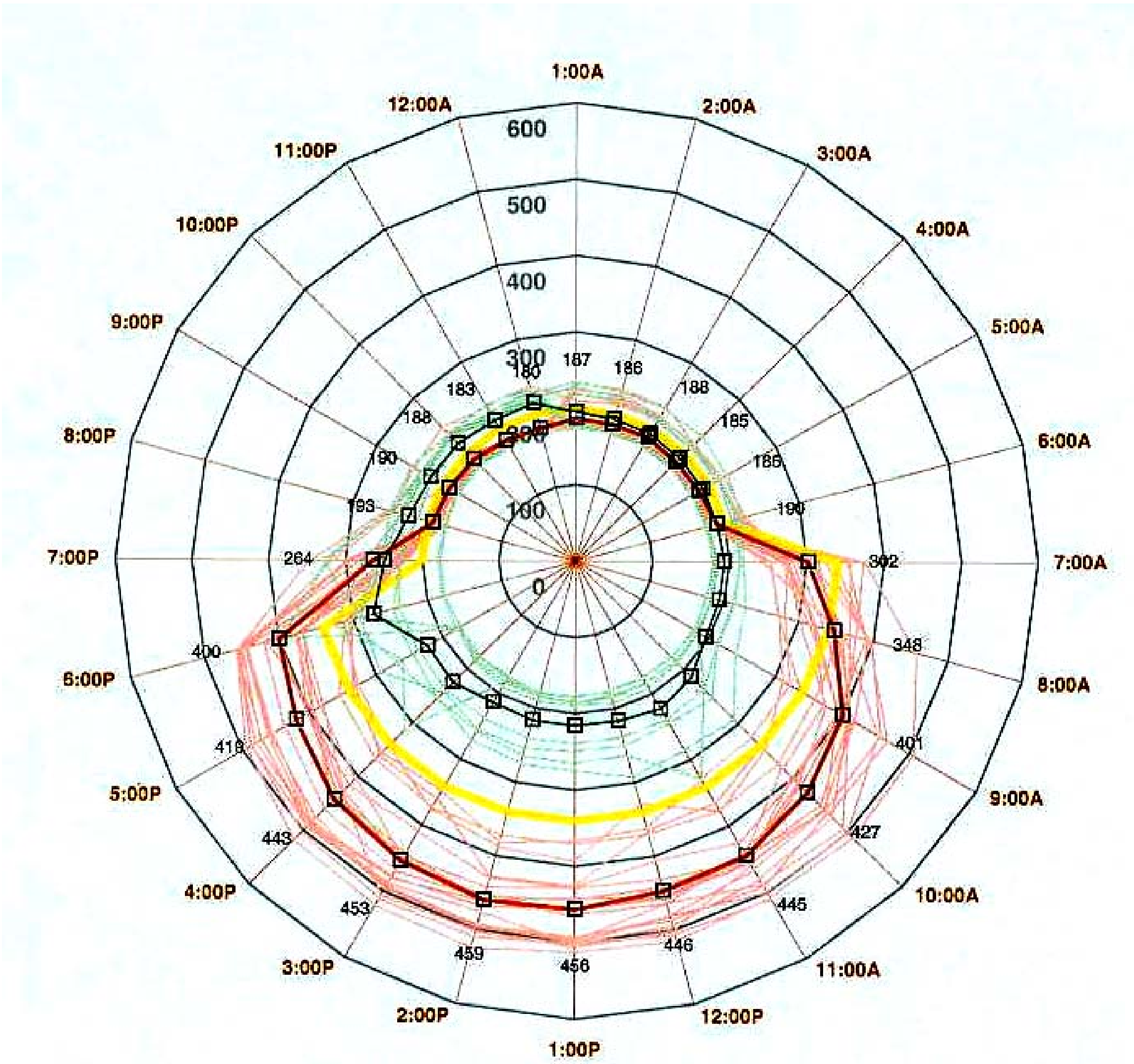

Figure 15: Sample Electricity Load Profile for June 2001

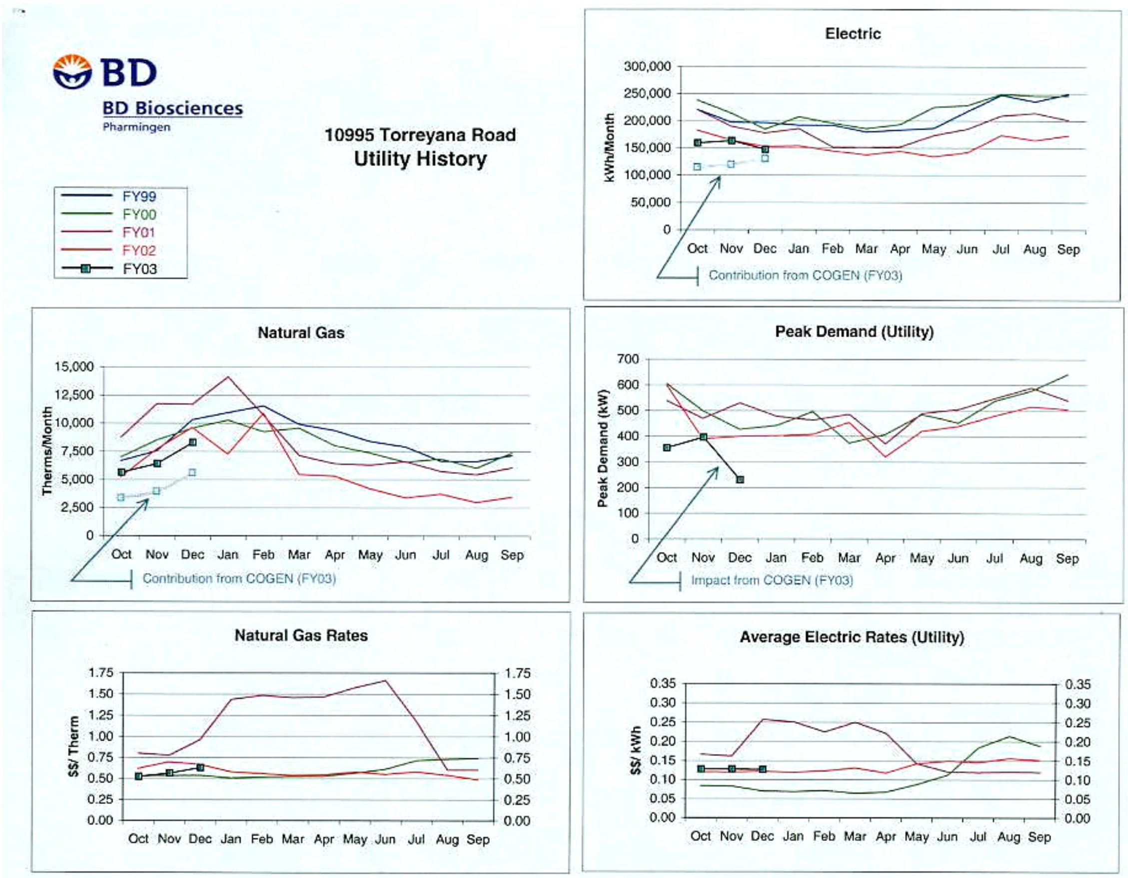

Figure 16: SDG&E Consumption and Costs for 10995 Torreyana Rd. Building

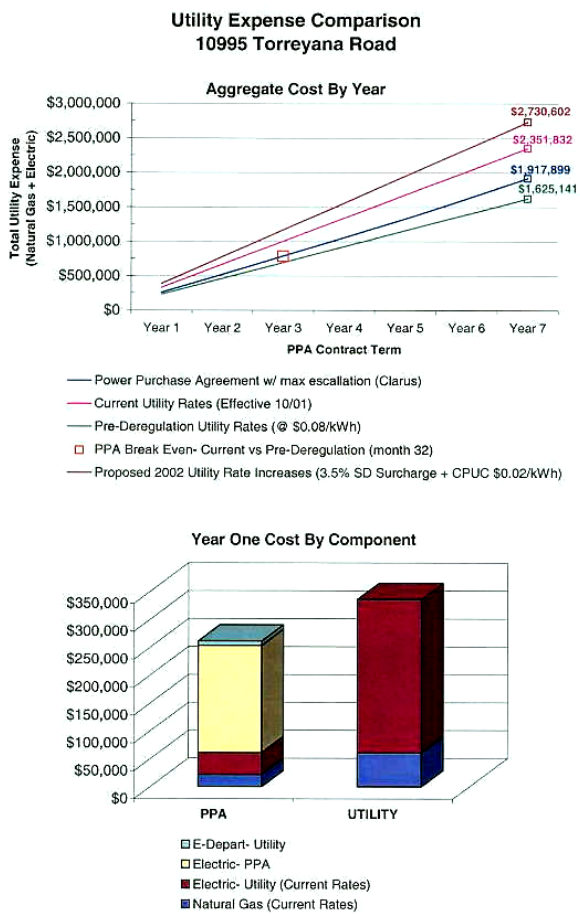

Figure 17: Estimates of Current Energy Costs and Savings

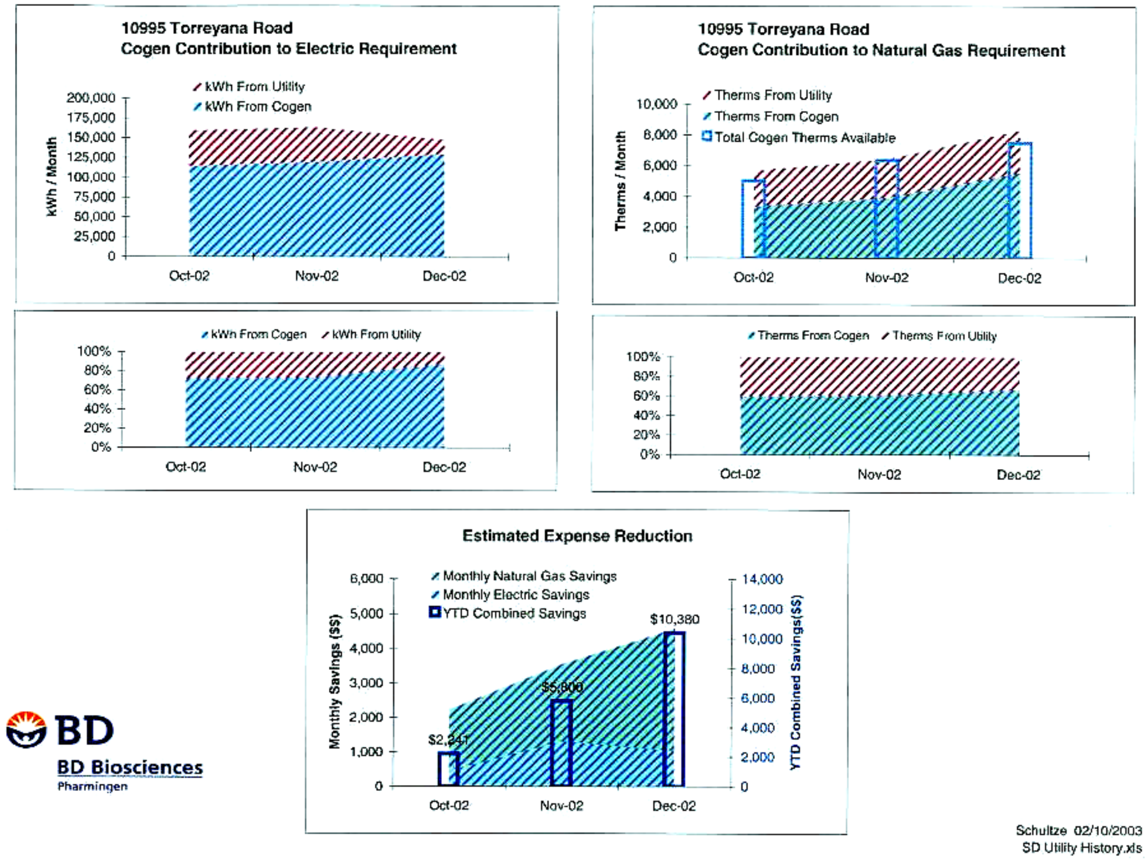

Figure 18: Performance Results from First Three Months of System Operation

Appendix D: System Performance Data Provided by Clarus Energy

The majority of DER-CAM simulation performed for this study was done in the summer of 2002. However, the Clarus Energy DER system was not in operation as reported until October 2002. In January 2003, Clarus Energy reported the system performance stated in this Appendix.

Table 5: Performance Data Reported By Clarus Energy

BD Bioscience Annual FERC Efficiency Summary

	Total kWh	Fuel Gas Therms	Total Waste Heat Therms	Waste Heat Used Therms	Engine Heat Rate BTU/kWh	FERC Eff. %
October	124,167	13,384	5,018	3,367	10,779	44.3%
November	131,784	14,387	6,371	3,947	10,917	45.0%
December	129,797	16,439	7,489	5,587	12,665	44.0%
Total	385,748	44,210	18,878	12,901	11,461	44.4%

Note: "Total kWh" comes from the SDG&E generator output meter. It is total kwh generated minus the parasitic loads.
" Fuel Gas" comes from the SDG&E gas meter. "Fuel Gas" is the total amount of fuel gas supplied to the generators.
" Total Waste Heat" and "Waste Heat Used" come from the on board monitoring system.

Load following capability was added to both machines on December 16, 2002, which allows the machines to follow the load of the building down to 50% of each machines capacity. The system has been achieving 99% availability since October 2002.

Appendix E: Economic Calculations Based on Data From Clarus Energy

Table 6: Analysis based on current electricity generation level (1,500,000 kWh/year)

		source
Capital Costs		
Project Capital Costs	$375,000	Clarus Energy
CPUC Subsidy	$112,500	Clarus Energy
Adjusted Project Capital Costs	$262,500	
Lifetime of Equipment	12.5	DER-CAM technology database
Discount Rate	0.075	DER-CAM assumption
Amortized Capital Cost	$33,085	
Fuel Costs		
Total annual generation (kWh)	1500000	Extrapolation of data provided by Clarus Energy
Heat Rate (kJ/kWh)	11461	Clarus Energy
Natural Gas Required (kJ LHV)	17191500000	
Natural Gas Required (kJ HHV)	19082565000	
Natural Gas Costs ($/kJ HHV)	5.1525E-06	SDG&E
Total Annual Natural Gas Cost	$98,323	
Operation and Maintenance Costs		
Installed Capacity (kW)	300	
Fixed ($/kW/year)	26.5	DER-CAM technology database
Fixed Annual O&M Costs	$7,950	
Annual Payment from Pharmingen		
Annual Payment From Pharmingen	$142,500	based on estimate of annual kWh purchased
Summary of Costs and Payments to Clarus		
Amortized Capital Cost	$33,085	
Natural Gas	$98,323	
Operation and Maintenance	$7,950	
Total Annual Costs to Clarus	**$139,358**	
Annual Payment to Clarus (from Pharmingen)	**$142,500**	
Annual Profit to Clarus	**$3,142**	

Table 7: Analysis based on current electricity generation level (1,800,000 kWh/year)

		source
Capital Costs		
Project Capital Costs	$375,000	Clarus Energy
CPUC Subsidy	$112,500	Clarus Energy
Adjusted Project Capital Costs	$262,500	
Lifetime of Equipment	12.5	DER-CAM technology database
Discount Rate	0.075	DER-CAM assumption
Amortized Capital Cost	$33,085	
Fuel Costs		
Total annual generation (kWh)	1800000	Extrapolation of data provided by Clarus Energy
Heat Rate (kJ/kWh)	11461	Clarus Energy
Natural Gas Required (kJ LHV)	20629800000	
Natural Gas Required (kJ HHV)	22899078000	
Natural Gas Costs ($/kJ HHV)	5.1525E-06	SDG&E
Total Annual Natural Gas Cost	$117,987	
Operation and Maintenance Costs		
Installed Capacity (kW)	300	
Fixed ($/kW/year)	26.5	DER-CAM technology database
Fixed Annual O&M Costs	$7,950	
Annual Payment from Pharmingen		
Annual Payment From Pharmingen	$171,000	based on estimate of annual kWh purchased
Summary of Costs and Payments to Clarus		
Amortized Capital Cost	$33,085	
Natural Gas	$117,987	
Operation and Maintenance	$7,950	
Total Annual Costs to Clarus	**$159,023**	
Annual Payment to Clarus (from Pharmingen)	**$171,000**	
Annual Profit to Clarus	**$11,977**	

Appendix F: Development of Hourly Load Profiles

DER-CAM requires hourly customer load values in five categories for a typical weekday and a typical weekend for each month of the year. The five categories are electric only (excluding cooling), electric cooling, water heating by natural gas, space heating by natural gas, and natural gas only. Schultze provided the figures in *Appendix C: Data Provided by BD Biosciences Pharmingen*, as well as more qualitative information in conversation, from which hourly load profiles were surmised by the following processes.

Electric-Only and Cooling Loads

Figure 15 provided load profiles for the month of June 2001. From this graph, it can be seen that the site has a base-load around 200 kW and weekday working hour (7 am to 6 pm) loads around 450 kW. Base-loads (mostly refrigeration) were assumed to be similar throughout the year.

Figure 16 provides data on historic monthly electricity consumption including cooling. From these, it was assumed that the increased consumption in June through October was due solely to cooling loads from an electric chiller. It was further assumed that cooling was only required during working hours. By assuming a typical dome shaped cooling load, this information was sufficient to generate cooling loads for the months of June through October, with cooling loads in other months assumed insignificant.

By subtracting the monthly cooling load totals from the monthly load data for 2001, the monthly electric-only loads were known. It was left to translate these monthly totals into hourly profiles. The profile of Figure 15 was used as a model of hourly electricity consumption. The shape shows base-load only from 6 pm to 7 am and on weekend with a dome-shaped increase in consumption during working hours. The profile was scaled for each month to match total electric consumption data (see). Electric-only load profiles were scaled down 15% to account for energy efficiency improvements implemented during 2001. This drop in energy consumption is seen in Figure 16.

Water Heating, Space Heating, and Natural Gas Only Loads

Monthly gas bills were provided by BD Biosciences Pharmingen and served as the basis for generating load profiles.

Water heating loads at this building were considered insignificant. Natural gas consumption is accounted for in the space heating and natural-gas-only loads.

Space heating loads were assumed to have a split-level profile with a high value in the night and morning (9 pm to 9 am) and a low value during the day. The higher and lower values were scaled based on historic daytime and nighttime temperatures in San Diego.

In this analysis, an efficiency of 80% was assumed for converting natural gas to useful heat.

Due to the nature of BD Biosciences Pharmingen's business, significant natural-gas-only loads were assumed during daytime hours to account for process heat and sterilization demands. It was assumed that these demands were constant throughout the year.

The space-heating and natural-gas-only profiles were scaled so that monthly natural gas consumption totals matched billing.

Load Profiles

Graphical depictions of the generated load data are presented in the following pages.

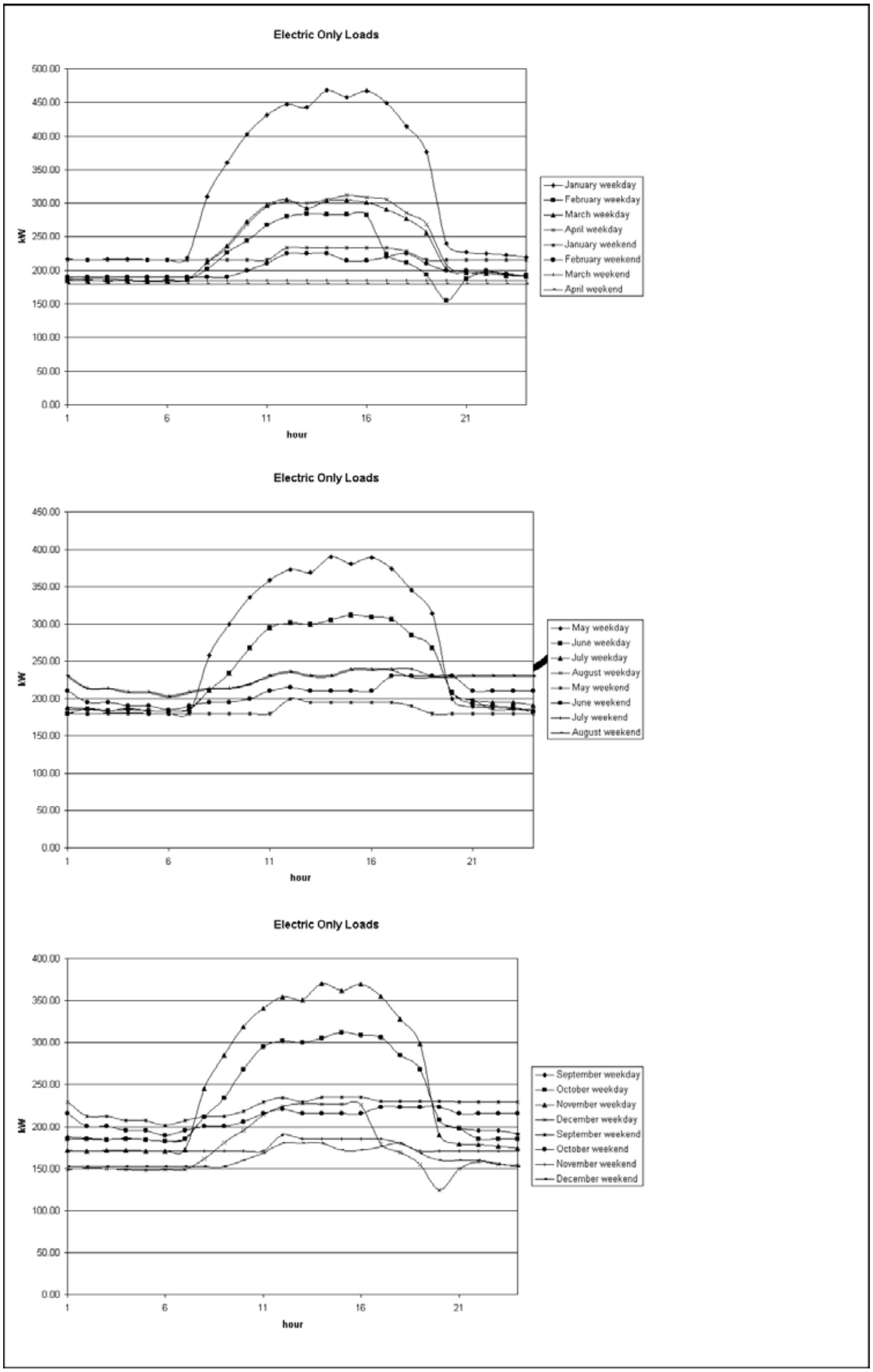

Figure 19: Electric Only Loads (excluding cooling)

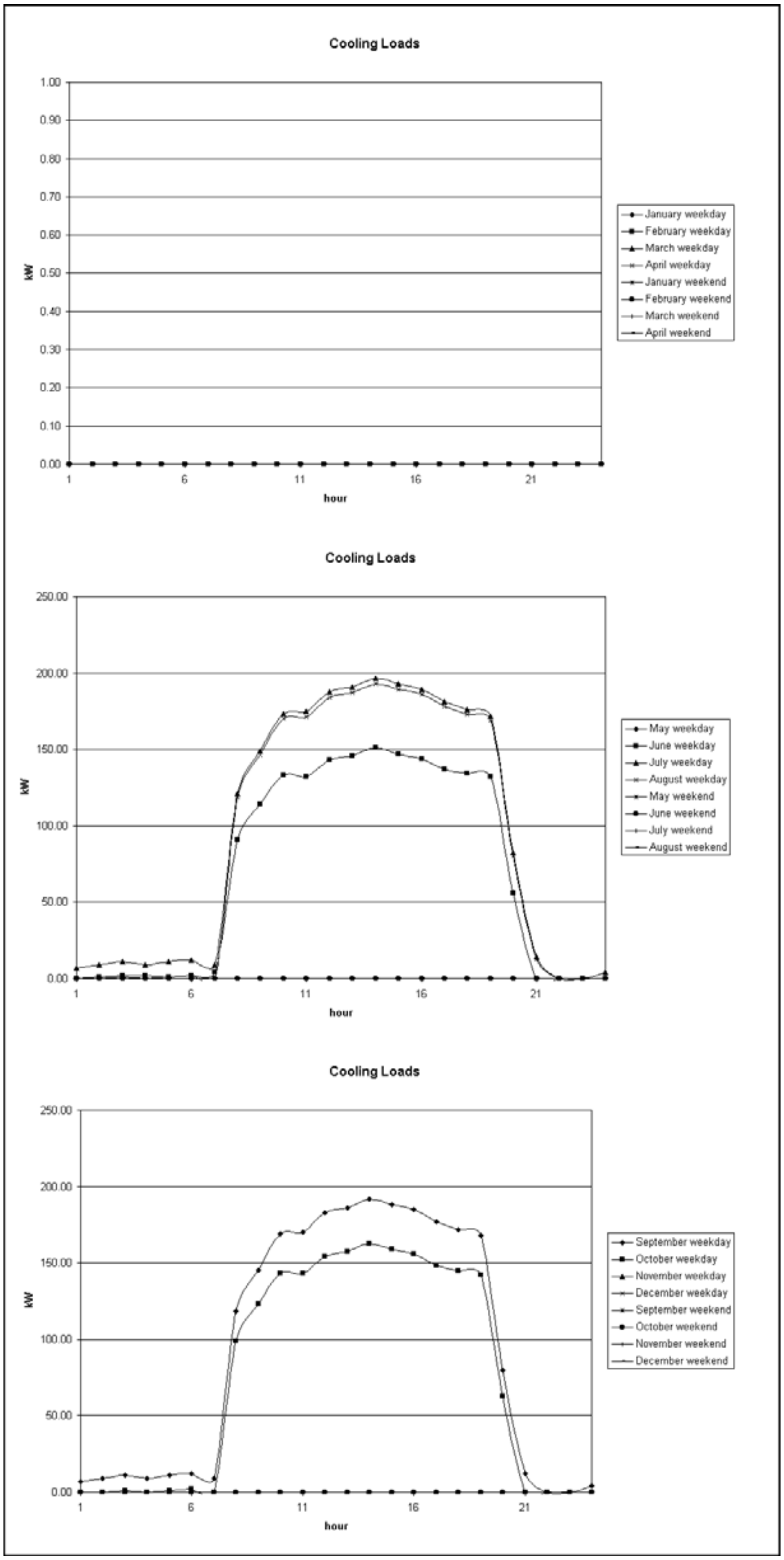

Figure 20: Cooling Loads

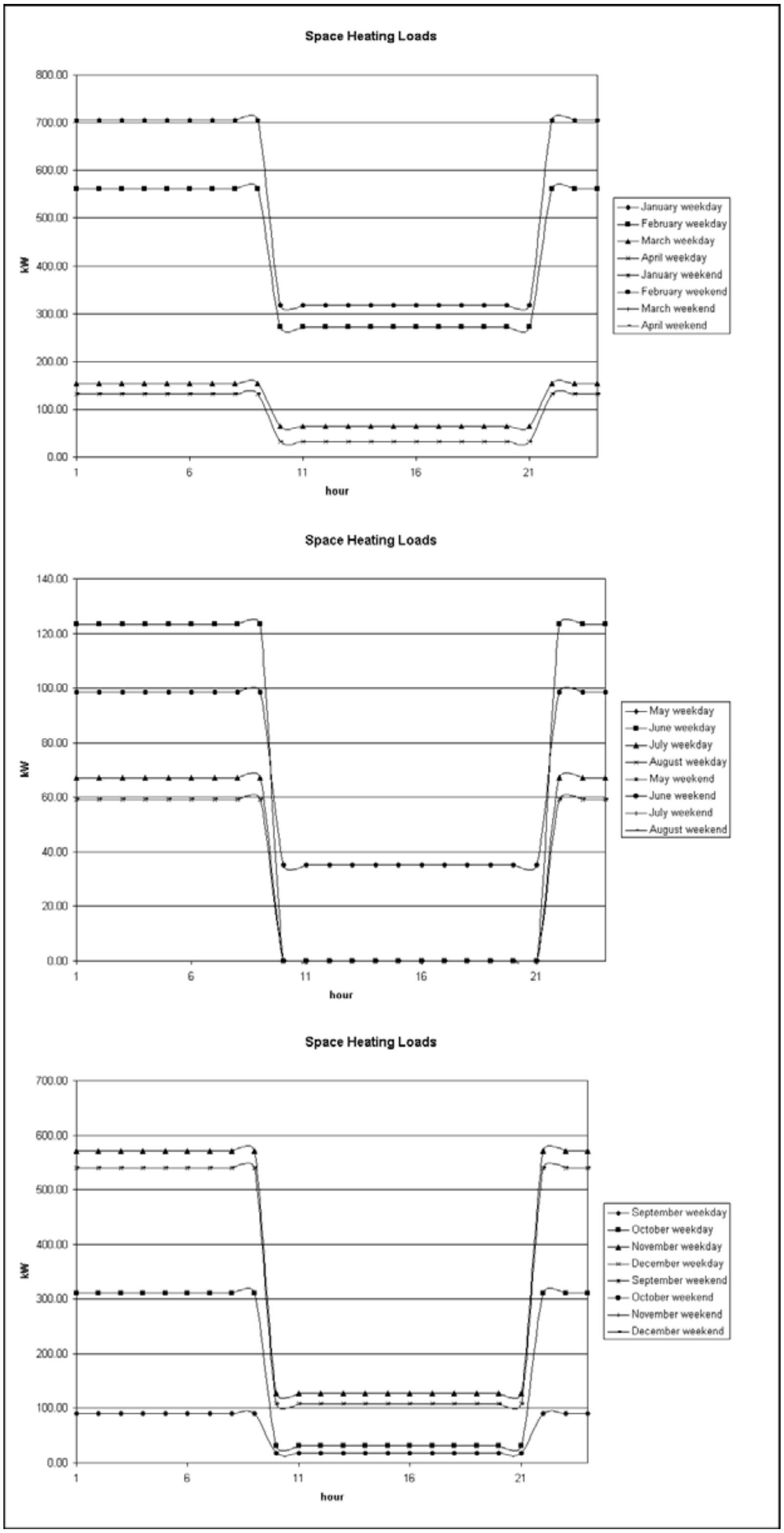

Figure 21: Space Heating Loads

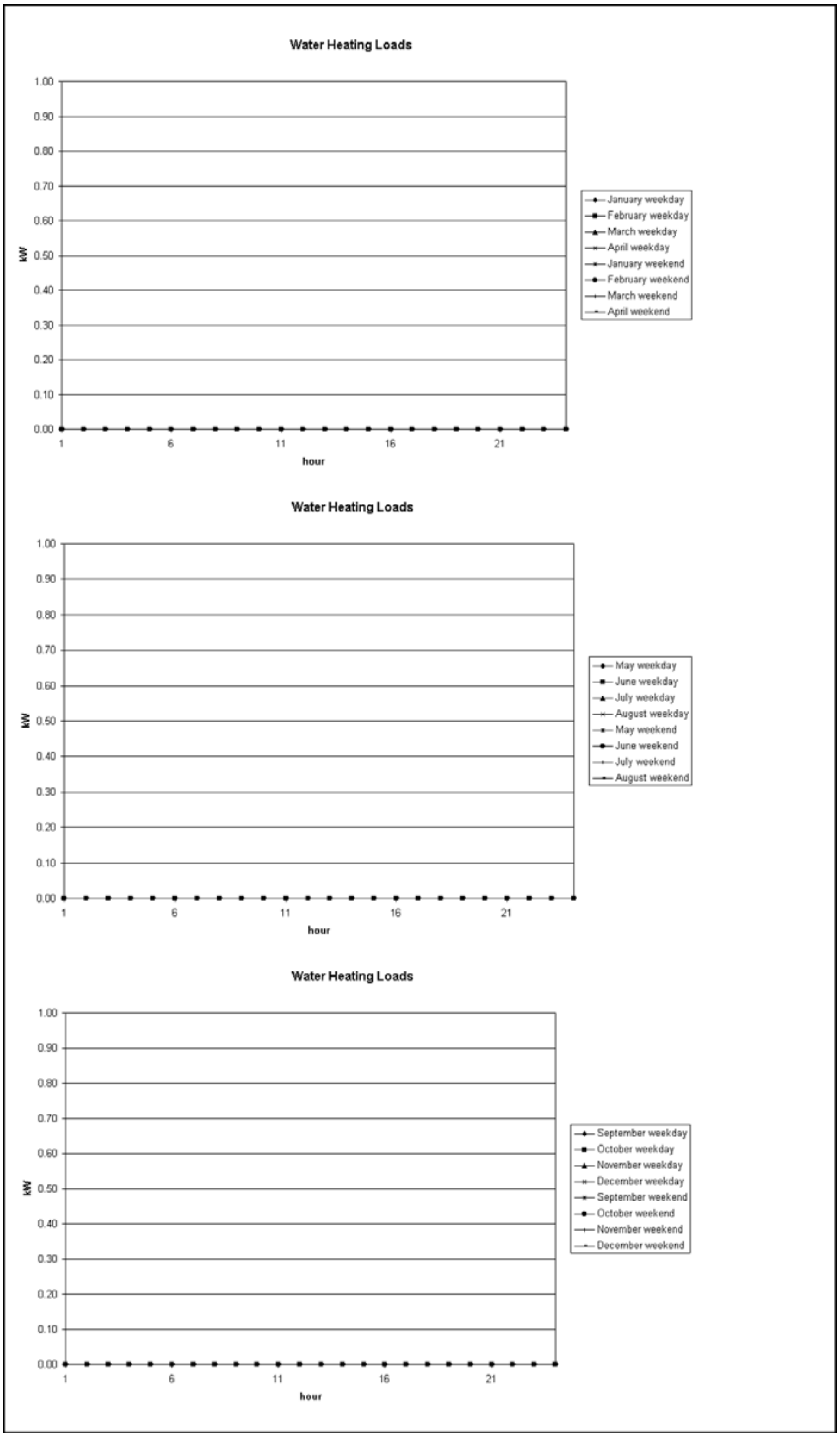

Figure 22: Water Heating Loads

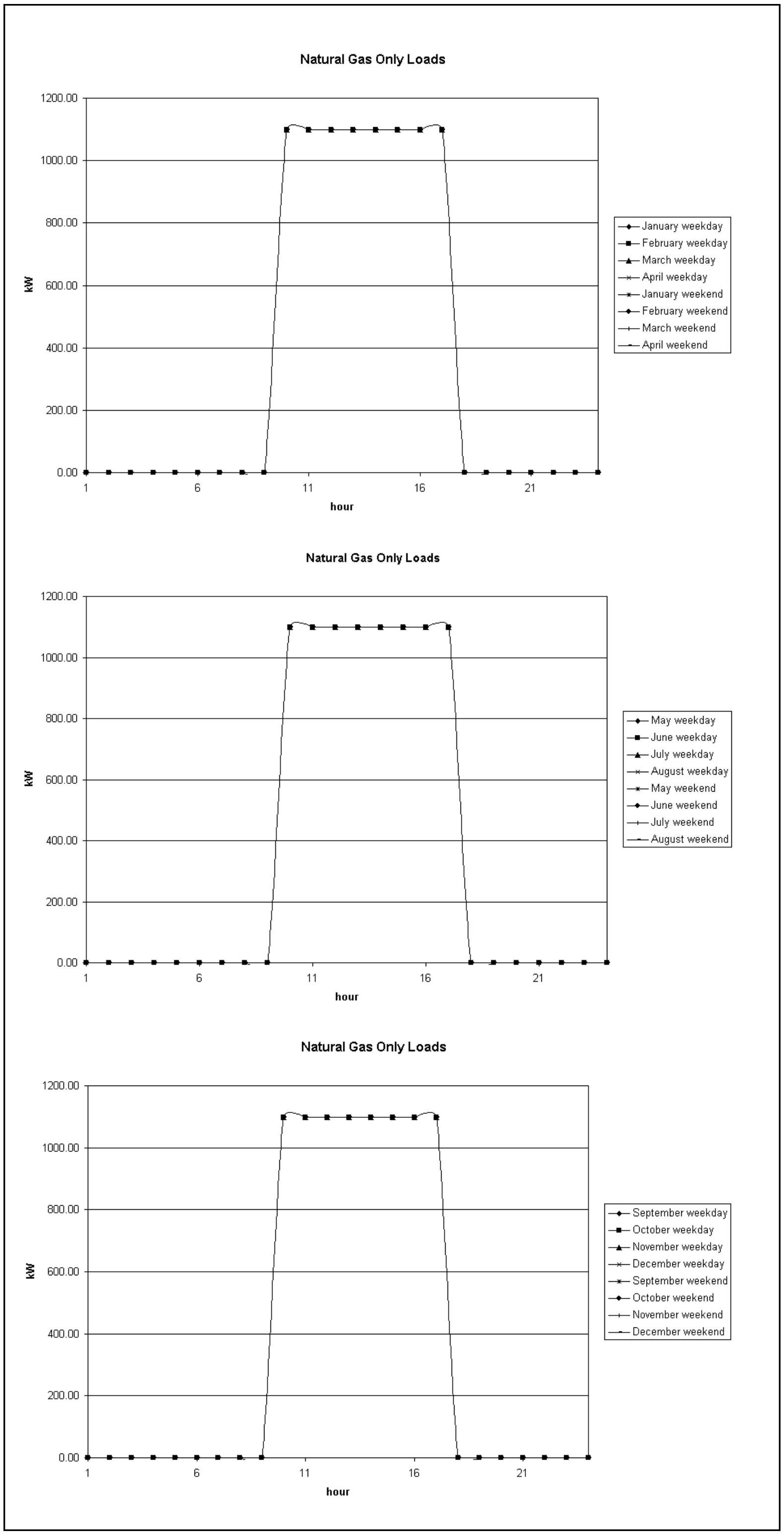

Figure 23: Natural Gas Only Loads

Appendix G: Summary of Tariffs

The following is a summary of San Diego Gas and Electric tariffs applicable during the period a DER system was being considered.

Table 8: SDG&E Electricity Tariffs for AL-TOU Customers

Definitions of Time and Season	Summer months	May-Sept
	Summer On Peak hours	11h-18h
	Summer Mid Peak hours	06h-11h, 18h-22h
	Summer Off Peak hours	00h-06h, 22h-24h
	Winter months	Jan- Apr, Oct- Dec
	Winter On Peak hours	17h-20h
	Winter Mid Peak hours	06h-17h, 20h-22h
	Winter Off Peak hours	00h-06h, 22h-24h
Energy Price ($/kWh)	Summer On Peak	0.1548
	Summer Mid Peak	0.1060
	Summer Off Peak	0.0857
	Winter On Peak	0.1486
	Winter Mid Peak	0.1037
	Winter Off Peak	0.0814
Time of Use Power Price (Demand Charge) ($/kW peak montly usage during particular time of day)	Summer On Peak	7.84
	Summer Mid Peak	0.00
	Summer Off Peak	0.00
	Winter On Peak	0.00
	Winter Mid Peak	7.48
	Winter Off Peak	0.00
Coincident Price ($/kW)	Summer On Peak	20.38
	Summer Mid Peak	20.38
	Summer Off Peak	20.38
	Winter On Peak	6.44
	Winter Mid Peak	6.44
	Winter Off Peak	6.44
Non-Coincident Peak Power Charge ($/kW peak monthly usage)		0.00
Standby Charge ($/kW DER Capacity)		0.00
Facility Charge ($/month)		43.50

Table 9: SDG&E Natural Gas Tariffs

month	cost ($/kJ)	cost ($/therm)
January	5.26E-06	0.55
February	4.99E-06	0.53
March	5.14E-06	0.54
April	4.40E-06	0.46
May	4.94E-06	0.52
June	4.71E-06	0.50
July	4.82E-06	0.51
August	5.28E-06	0.56
September	5.39E-06	0.57
October	5.31E-06	0.56
November	5.60E-06	0.59
December	5.99E-06	0.63

Appendix H: DER-CAM Technology Data

The following cost and performance of generation technologies data was used in DER-CAM.

Table 10: Microturbine Data

	with heat recovery	with absorption cooling		Capacity (kW)	Lifetime (years)	Capital Costs* ($/kW)	Capital Costs with CPUC rebate ($/kW)	Operation and Maintenance Fixed Costs ($/kW)	Operation and Maintenance Variable Costs ($/kWh)	Heat rate (kJ/kWh)
30 kW microturbine				30	13	1862	1862	0.0000	0.0150	14400
30 kW microturbine				30	13	1862	1862	0.0000	0.0150	13800
60 kW microturbine				60	13	1290	1290	0.0000	0.0150	12900
30 kW microturbine	x			30	13	2546	1782	0.0000	0.0150	14400
30 kW microturbine	x			30	13	2546	1782	0.0000	0.0150	13800
60 kW microturbine	x			60	13	2358	1610	0.0000	0.0130	12900
30 kW microturbine		x		30	13	3352	2352	0.0000	0.0150	14400
30 kW microturbine		x		30	13	3352	2352	0.0000	0.0150	13800
60 kW microturbine		x		60	13	2322	1625	0.0000	0.0150	12900
30 kW microturbine	x	x		30	13	5898	4898	0.0000	0.0150	14400
30 kW microturbine	x	x		30	13	5898	4898	0.0000	0.0150	13800
60 kW microturbine	x	x		60	13	3997	2997	0.0000	0.0150	12900

*Costs were derived from data received from Andrew Wang of Capstone Microturbines, June 2002

Table 11: Natural Gas Engine Data

	with heat recovery	with absorption cooling	Capacity (kW)	Lifetime (years)	Capital Costs ($/kW)	Capital Costs with CPUC rebate ($/kW)	Operation and Maintenance Fixed Costs ($/kW)	Operation and Maintenance Variable Costs ($/kWh)	Heat rate (kJ/kWh)
25 kW natural gas engine			25	13	1536	1536	0.0000	0.0150	12000
55 kW natural gas engine			55	13	1008	1008	0.0000	0.0150	12000
100 kW natural gas engine			100	13	902	902	0.0000	0.0150	11321
150 kW natural gas engine			150	13	1097	1097	0.0000	0.0150	10919
500 kW natural gas engine			500	13	856	856	0.0000	0.0150	10714
25 kW natural gas engine	x		25	13	1731	1212	0.0000	0.0150	12000
55 kW natural gas engine	x		55	13	1162	813	0.0000	0.0150	12000
100 kW natural gas engine	x		100	13	1092	764	0.0000	0.0150	11321
150 kW natural gas engine	x		150	13	1261	883	0.0000	0.0150	10919
500 kW natural gas engine	x		500	13	1006	704	0.0000	0.0150	10714
25 kW natural gas engine		x	25	13	3036	2036	0.0000	0.0150	12000
55 kW natural gas engine		x	55	13	2005	1404	0.0000	0.0150	12000
100 kW natural gas engine		x	100	13	1990	1393	0.0000	0.0150	11321
150 kW natural gas engine		x	150	13	1893	1325	0.0000	0.0150	10919
500 kW natural gas engine		x	500	13	1294	906	0.0000	0.0150	10714
25 kW natural gas engine	x	x	25	13	4438	3438	0.0000	0.0150	12000
55 kW natural gas engine	x	x	55	13	2838	1987	0.0000	0.0150	12000
100 kW natural gas engine	x	x	100	13	2754	1928	0.0000	0.0150	11321
150 kW natural gas engine	x	x	150	13	2827	1979	0.0000	0.0150	10919
500 kW natural gas engine	x	x	500	13	1972	1380	0.0000	0.0150	10714

*Data collected from major engine manufacturers, heat rates specifically from Coastintelligen

Table 12: Diesel Engine Data

	Capacity (kW)	Lifetime (years)	Capital Costs ($/kW)	Operation and Maintenance Fixed Costs ($/kW)	Operation and Maintenance Variable Costs ($/kWh)	Heat rate (kJ/kWh)
15 kW Katolight diesel engine	15	12.5	2257	26.50	0.0000	18288
30 kW Katolight diesel engine	30	12.5	1290	26.50	0.0000	11887
60 kW Katolight diesel engine	60	12.5	864	26.50	0.0000	11201
105 kW Katolight diesel engine	105	12.5	690	26.50	0.0000	10581
200 kW Katolight diesel engine	200	12.5	514	26.50	0.0000	11041
350 kW Katolight diesel engine	350	12.5	414	26.50	0.0000	10032
500 kW Katolight diesel engine	500	12.5	386	26.50	0.0000	10314
8 kW Cummins diesel engine	8	12.5	627	26.50	0.0000	10458
20 kW Cummins diesel engine	20	12.5	1188	26.50	0.0000	12783
40 kW Cummins diesel engine	40	12.5	993	26.50	0.0000	11658
100 kW Cummins diesel engine	100	12.5	599	26.50	0.0000	10287
200 kW Cummins diesel engine	200	12.5	416	26.50	0.0000	9944
300 kW Cummins diesel engine	300	12.5	357	26.50	0.0000	10287
500 kW Cummins diesel engine	500	12.5	318	26.50	0.0000	9327

*Data collected from Cummins and Katolight

Table 13: Fuel Cell Data

	with heat recovery	with absorption cooling	Capacity (kW)	Lifetime (years)	Capital Costs* ($/kW)	Capital Costs with CPUC rebate ($/kW)	Operation and Maintenance Fixed Costs ($/kW)	Operation and Maintenance Variable Costs ($/kWh)	Heat rate (kJ/kWh)
200 kW Phosphoric Acid Fuel Cell			200	12.5	4000	4500	0.00	0.0153	9480
200 kW Phosphoric Acid Fuel Cell	x		200	12.5	5359	3252	0.00	0.0153	9480
200 kW Phosphoric Acid Fuel Cell		x	200	12.5	6337	3840	0.00	0.0153	9480
200 kW Phosphoric Acid Fuel Cell	x	x	200	12.5	7256	4756	0.00	0.0153	9480

*Costs (without rebates) for the 200 kW fuel cell were obtained from Gauranteed Savings Building case study, Bailey *et al* (2003)

Table 14: Photovoltaic Data

	Capacity (kW)	Lifetime (years)	Capital Costs ($/kW)	Capital Costs with CPUC rebate ($/kW)	Operation and Maintenance Fixed Costs ($/kW)	Operation and Maintenance Variable Costs ($/kWh)
5 kW photovoltaic system	5	20	8650	4325	14	0
20 kW photovoltaic system	20	20	7450	3725	14	0
50 kW photovoltaic system	50	20	6675	3338	12	0
100 kW photovoltaic system	100	20	6675	3338	11	0

*costs obtianed from Jeff Oldman, Real Goods, summer 2001

Appendix I: Net Present Value and Internal Rate of Return Analyses

DER-CAM selects an optimal project based on maximum bill savings, but other criteria and analyses could be used to select DER systems, so results from DER-CAM may vary from site adoption decisions. Here, the internal rate of return (IRR) is used to illustrate why a DER system of maximum energy savings is not necessarily the optimal investment. Additionally, it is demonstrated that project economics can be affected by the business model.

For this example, the BD Biosciences Pharmingen case is used and the purchases of zero, one, two, three, and four 150 kW natural gas engines with heat recovery are considered. For each purchase choice, DER-CAM is used to determine the yearly energy bill, excluding amortized capital costs. From this, yearly savings are determined and the net present value of yearly savings over the lifetime of the equipment is calculated[1]. The net present value (NPV) of the project is then the difference between net present bill savings and upfront capital costs.

The IRR is defined as the discount rate at which the NPV of the project would be zero. Investors will select a rate of return above which a project is worth implementing. For a project with little uncertainty, a rate of return above current interest rates may be acceptable. For projects with a more risk, a higher rate of return may be required.

Analysis From The Combined Perspective of Site and Provider

Analyses were preformed from the combined perspective and the site and the provider. This would be the situation if the site decided to purchase and install DER on their own. Table 15 presents the data for the NPV and IRR analyses. The three-generator system has the maximum NPV: this is what DER-CAM selects as the optimal DER system when it is restricted to purchasing only this type of generator but not restricted in the quantity of generators to purchase. However, the IRR is continuously decreasing as more generators are purchased. Although NPV is maximized with the purchase of three generators, the IRR for this system is less than for smaller systems. If a site is interested in a successful, profitable project, they may desire a larger IRR than that achieved for the three-generator purchase. This might be the case for a site new to DER and interested in a trial project.

[1] For this analysis, an equipment lifetime of 12.5 years and an interest rate of 7.5% was assumed.

Table 15: Economic Analyses From Combined Perspective

Number of 150 kW engines purchased	***0***	***1***	***2***	***3***	***4***
Installed Capacity (kW)	0	150	300	450	600
Yearly Energy Costs	$333,733	$269,395	$233,996	$223,832	$238,276
DER-CAM Self Generation Capital Costs	$0	$114,600	$229,200	$343,800	$458,400
Self Generation Capital Costs (Amortized)	$0	$14,444	$28,888	$43,332	$57,776
Yearly Energy Costs Less Self-Gen Capital Costs	$333,733	$254,951	$205,108	$180,500	$180,500
Yearly Annual Energy Savings (Dividend)	$0	$78,782	$128,625	$153,233	$153,233
Present Value of Annual Savings	$0	$625,061	$1,020,518	$1,215,762	$1,215,762
Net Present Value	$0	$510,461	$791,318	$871,962	$757,362
Internal Rate of Return		69%	56%	44%	32%

Analysis From The Perspective of the Provider

The previous analysis assumes that the DER investor and the energy user are one and the same. The energy user purchases DER equipment upfront and reaps the benefits of the investment in the form of uniform annual energy bill savings. This same analysis was performed from the perspective of Clarus Energy. Clarus Energy accepted the capital costs of this project and in return receives payments for electricity from the site. This more accurately describes the actual business case but must make the additional assumption of the fixed $/kWh price of electricity that Clarus Energy provides to the site[1].

Table 16 presents the data for this analysis. Here is it seen that Clarus Energy chose roughly a breakeven project (for reasons discussed in the body of this report) from their perspective, i.e. the NPV is near zero, the IRR is near the discount rate. The reason for optimal DER selection varying with perspective is that Clarus Energy receives no financial benefit for providing the site with recovered heat from the system, while the site

[1] Clarus Energy did not disclose their selling price of electricity to the site. A reasonable estimate was made based on information provided by the site and by Clarus Energy.

does benefit financially from the recovered heat. Thus, successive generators are not used as much as the previous generators. The second and third generators, which are often not in use, are economically attractive to the site (considering electricity and heating) but not to Clarus Energy (only considering electricity).

Table 16: Economic Analysis From Clarus Energy Perspective

Number of 150 kW engines purchased	***0***	***1***	***2***	***3***	***4***
Installed Capacity (kW)	0	150	300	450	600
DER-CAM Self Generation Capital Costs	$0	$114,600	$229,200	$343,800	$458,400
Yearly Revenue From BD Biosciences Pharmingen	$0	$102,509	$146,108	$159,906	$159,906
Yearly Operation and Maintenance Costs (including NG purchase)	$0	$86,318	$118,709	$127,879	$127,879
Yearly Annual Dividends	$0	$16,191	$27,400	$32,027	$32,027
Present Value of Annual Dividends	$0	$128,459	$217,390	$254,106	$254,106
Net Present Value of Project	$0	$13,859	-$11,810	-$89,694	-$204,294
Internal Rate of Return		10%	7%	2%	-2%

Appendix J: Installation of Generators in Housing

Coastintelligen provided the two 150 kW natural gas engines inside of a container for ease of installation and noise reduction. The pictures in this appendix illustrate the installation process.

Figure 24: Generator Site During Construction

Figure 25: Placement of the Container

Figure 26: Generators in Place